TECHNOLOGY SUPPLY CURVES FOR LOW-CARBON POWER GENERATION

A report to the Committee on Climate Change

June 2013

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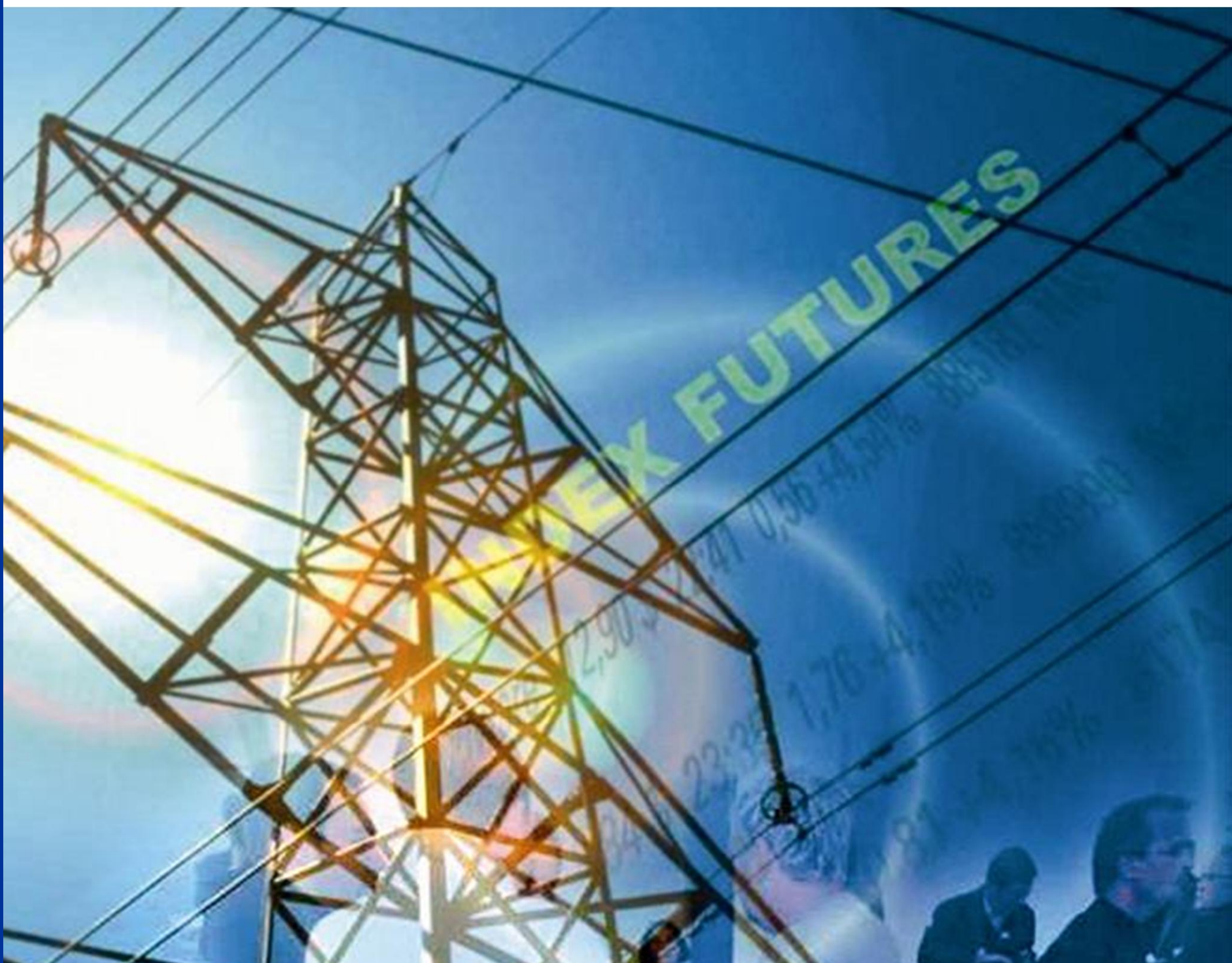

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Introduction

Background

The Committee on Climate Change (the "Committee") provides advice to government on climate change issues, and particularly the setting of carbon budgets for the UK. In relation to the electricity sector, this advice is based on developing feasible scenarios of future decarbonisation, derived from an understanding of technology costs and the potential for, and speed of, future deployment. The Committee wishes to review its scenarios for power sector decarbonisation in the light of recent industry developments, and, in particular, the Government's Electricity Market Reform proposals.

Objectives

The aim of this study is to update the Committee's view of the potential deployment of five key low-carbon electricity technologies expected to make significant contributions to decarbonising the electricity sector by 2030, to update its view of the costs of these technologies, and to understand what levels of support might be required to achieve this deployment.

The technologies considered are:

- onshore wind;
- offshore wind;
- nuclear;
- CCS (based on gas or coal); and
- biomass conversion – i.e. conversion of existing coal fired generating units to run on biomass.

Approach

First, we investigate how deployment could proceed taking account of the different stages of project development (such as consenting, construction, and operation) and examining capability at each stage. The aim is to understand the existing project pipeline, what deployment might be achieved by 2030, what are the key factors limiting deployment, and what policy 'enablers' might be available or required to mitigate these limitations. In general these feasible deployment 'timelines' are 'high effort' deployment scenarios – meaning that we assume a continued commitment from the Government to achieve its carbon goals and hence a willingness to implement policies to support the significant growth of low-carbon generation required.

Second, we compare recent reported evidence on technology costs with the Committee's previous assumptions and update where necessary. We then use these cost assumptions to derive a detailed cost distribution for each technology showing the range of costs across the full range of potential projects. For onshore and offshore wind we adopt a more 'bottom-up' costing approach owing to the need to derive cost across a large number of projects. Costs are expressed as the levelised cost of electricity (LCOE) (in £/MWh), taking account of capital and operating costs and assuming the generator will require a specified rate of return on its investment. In assessing costs we take account of the potential for costs to change over time as a result of technology learning and

reductions in the required rate of return as a technology matures and is perceived as less risky.

We then use the cost distributions to assess the level of support (expressed as Contract for Difference (CfD) strike prices) likely to be required for each technology consistent with achieving deployment in line with the projected deployment timeline. Knowledge of the strike prices required to achieve the deployment timeline for each technology then allows us to evaluate the total support costs required, as well as the 'resource cost' (i.e. the net cost) associated with this support.

Study limitations

It is important to understand the limitations of a study of this nature, especially given the ambitious objective of examining the future evolutions of costs and deployment for five different low-carbon technologies out to 2030. Levelised cost estimates are inherently uncertain, and are driven by underlying assumptions on capital and operating costs, fuel prices, load factor, discounts rates, and how costs might change over time as a technology matures – all of which are themselves uncertain.

As a result of these limitations and uncertainties, the results presented here should not be regarded as firm predictions of the future. They should be viewed as illustration of what might happen to deployment given certain conditions, or of what strike prices might be required based on the costs we derive. To put this uncertainty into context we have performed sensitivity analysis to understand the impact of uncertainty in key cost drivers on required strike prices. However these ranges do not themselves necessarily capture the range of possible outcomes.

Considering feasible deployment timelines

For each technology we project what level of deployment might be feasible by 2030 given sufficient policy commitment from the Government (including successful implementation of CfD FiTs) – see Table 1. The Committee developed deployment scenarios for the Fourth Carbon Budget in 2010 and later for its Renewable Energy Review in 2011, but our updated projections take account of developments since then. In particular our projections for nuclear and CCS deployment by 2030 are lower than the Committee's higher deployment scenarios for these technologies owing to delays in reaching Final Investment Decisions for the first projects.

Table 1 – Summary of projected feasible deployment timelines

	Projected deployment (GW)			
Technology	Current (3)	2020	2030	Key constraints
Offshore wind	3	12-15	25-40	Construction finance, supply chain capacity
Onshore wind	5	15	25	Planning process
(New) nuclear (1)	0	0(2)	16	Number of developers and construction finance
CCS	0	0.6	10	Implementation of pre-commercial plants
Biomass conversion	0.7	4	2 (4)	Government ambition

Notes:
(1) Existing nuclear generating capacity not included
(2) The first new reactor is commissioning in 2020
(3) As of January 2013, based on snapshot from Renewable UK's Wind Energy Database
(4) Biomass conversion capacity declines in the late 2020s as ageing plants retire

Offshore wind

The UK has a very large potential for offshore wind, with a large pipeline of potential projects established under The Crown Estate leasing rounds. The industry is still relatively immature but has expanded rapidly in recent years. Given the availability of sites, the key constraint on growth is supply chain capacity in general, and in particular access to finance during the construction phase.

Nevertheless we project that 25GW can be deployed by 2030 with continued moderate growth in supply capacity (with maximum deployment rates remaining below 2GW/yr). We also develop a higher deployment scenario under which 40GW is installed by 2030, with maximum deployment rates remaining below 3GW/yr. If these higher deployment rates are achieved then new leasing rounds may be required in the 2020s to maintain the momentum for more ambitious long-term deployment.

Onshore wind

As for offshore wind, there is a strong pipeline of potential projects, with around 15GW of capacity at various stages of development in addition to the approximately 5GW already in operation. Gaining planning consent remains a major challenge, and deployment is constrained by the rate of determination of applications and the proportion of applications which are approved.

Our deployment projections suggest that around 25GW can be achieved by 2030 based on the assumption that the planning system can continue to process applications at current levels. This figure is higher than the Committee's previous assessment of around 21GW, and reflects the fact that new projects have continued to come forward at a healthy rate since that assessment. Streamlining the planning process or increasing planning system capacity could lead to even higher deployment.

The overall long-term potential of onshore wind is not well understood, and may be determined by public attitudes to onshore wind rather than availability of sites. Public and political attitudes to onshore wind feed through into planning decisions, which in turn affect the availability of suitable sites (and can also impact project development costs).

Nuclear

Nuclear power will not make any significant contribution until the 2020s, but we project that 16GW can be achieved by 2030, assuming projects are realised on the five sites currently under active development. This assumes a successful GDA process for Horizon's ABWR reactor, and no further significant delays in the development process and no withdrawals by developers. A key concern is the small number of developers and potential lack of availability of finance during the pre-development and construction phases. This might be the limiting factor on nuclear deployment.

The three remaining sites identified in the National Planning Statement for Nuclear offer the potential to expand beyond 16GW to around 21-25GW, but it is likely that new developers will be needed in the market in order to realise this potential. A new round of site identification will be required to achieve even higher deployment in the long term and this process should begin towards the end of this decade.

CCS

CCS technology is still at an early stage of development. Progress in developing the first pre-commercialisation projects has been slower than we projected when we developed milestones for CCS roll-out for the Committee in 2009. As a result, we now project that around 10GW is an upper limit to what might realistically be deployed by 2030, and that CCS will not play a significant role in the generation mix until the late 2020s.

We retain our view that, in addition to the first two pre-commercial plants supported through the UK CCS Commercialisation Programme, a second phase of full scale pre-commercialisation plants will be required before full commercial roll-out. However achievement of 10GW by 2030 requires that some investors will be willing to commit to commercial projects before these second phase plants are operational.

Our deployment projections assume the early development of an integrated or co-ordinated approach to provision of transport and storage infrastructure in order to access early cost reductions and reduce risk for projects.

Biomass conversion

The existing coal generation fleet offers the potential for biomass conversions to play a role in decarbonisation of the electricity sector to 2030, but not for the longer term owing to the age of this fleet. We project that the amount of capacity which converts may be limited to around 4GW, based on our assessment of availability of government support rather than the availability of sufficient sustainable biomass available to support this capacity. Biomass conversions are likely to be implemented relatively quickly as developers compete for fuel supply and for available support.

Technology cost distributions

A key objective of the study is to derive technology cost distributions for each of the low-carbon technologies. A view of the distribution of costs across the range of potential projects is important for understanding required support costs for each technology and how these may change over time as deployment delivers cost reductions through learning.

The starting point is work carried out for the Committee by Mott MacDonald in 2011[1], but we have also considered more recent evidence where available and (particularly in the case of offshore and onshore wind) used in-house expertise to introduce more differentiation in the supply curve by modelling a wider range of projects. However there is a high degree of uncertainty in estimating costs, both because of uncertainty about the 'current cost' of a project and uncertainty about how this might change over time as a result of technology learning and of changing rates of return required by investors in response to changing perceptions of project risk.

Costs are expressed as levelised costs over the lifetime of the project. Table 2 presents our input assumptions for some of the key input assumptions, following which we summarise the resulting cost distributions. There are our 'central' estimates before considering uncertainty in input assumptions.

Table 2 – Key cost input assumptions

'Current' costs

Technology	Current capex costs (£m/MW)	Current discount rate (4)	Selected other key input assumptions
Offshore wind	2.4-3.0 (2)	12.4%	Opex 122-214/kW/yr, load factor 40-47%
Onshore wind	1.2-1.5	9.6%	Opex 37-73/kW/yr, load factor 22-31%
Nuclear	3.0-4.1	11.0%	60year operating life.
CCS	1.2-3.0 (3)	15.0%	Transport and storage cost £11/teCO_2, fuel cost based on DECC projections
Biomass conversion	0.25-0.45	10.0%	Fuel cost £6-8/GJ

Future cost development

Technology	Long term discount rate (5)	Technology learning assumptions
Offshore wind	9.1%	Learning rate 6% for capex, 10% for opex
Onshore wind	9.1%	No learning in base case
Nuclear	9.2%	Primarily driven by transition from FOAK to NOAK
CCS	10.0%	Primarily driven by transition from ZOAK to FOAK to NOAK
Biomass conversion	10.0%	No learning

Notes:
(1) Summary table only. For full details see main report.
(2) Offshore wind capex excludes OFTO cost of assets, which is treated as an opex cost.
(3) CCS capex excludes transport & storage, which is treated as opex. Range reflects different capture technologies.
(4) Discount rates are expressed in pre-tax real terms.
(5) The date by which the 'long term' discount rate is reached varies by technology.

[1] MML (2011b)

Offshore wind

The cost distribution for offshore wind is relatively flat, with the majority of projects showing 'current costs' in the range £140-160/MWh. In addition it is very difficult to generalise about which projects are cheaper and which are more expensive, for example by leasing round or location. We assume costs fall significantly over time as a result of learning and reducing discount rates. Levelised costs approach £100/MWh by 2030 but generally remain above this level.

Onshore wind[2]

Owing to the large number of potential onshore wind projects it is not practical to assess costs on an individual project basis – instead we have grouped projects into a number of different cost categories and geographic zones. Based on our analysis, the range of onshore costs for the existing project pipeline is around £70-110/MWh, with most of the potential volume (around 20TWh per annum) in the range £80-100/MWh. In general projects are cheaper if they are above 50MW in size or if they are in Scotland.

Compared to offshore wind, the potential for future cost reductions through learning or reduced discount rates is much lower.

Nuclear

We base our cost assumptions for nuclear power on the latest Parsons Brinckerhoff study for DECC. We assume ABWR is slightly cheaper than PWR. The early projects have a levelised cost in the range £80-95/MWh falling to £65-75/MWh for projects commissioning in the late 2020s (where the upper end of the range corresponds to PWR and the lower end to ABWR reactors).

CCS

In general gas CCS appears cheaper than coal CCS. However given the uncertainties involved, it is difficult to form a firm view as to which of the sub-technologies for a given fuel is cheapest. However we assume costs will reduce significantly for the successful technologies, driven in particular by reducing discount rates. Our cost distributions also assume that CO_2 transport and storage costs are essentially 'commoditised', meaning that there is a well-developed T&S infrastructure which reduces the risk of individual CCS projects by insulating them from wider T&S infrastructure risks.

Based on these assumptions, we project that the cost of commercial projects in the late 2020s is around £100/MWh, although the early pre-commercialisation projects are likely to be significantly more expensive (£120-160/MWh, depending on capture technology).

Biomass conversion

Most biomass conversion projects have a similar cost (around £80-90/MWh) since the existing coal fleet comprises a number of similar stations. There will be some differences based on plant size and fuel logistics, and the condition of the existing station (although this is hard to determine).

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2 This study is published shortly after publication by DECC of the results of its Call for Evidence on the costs of onshore wind. However our analysis was undertaken before this was published and we had no access to the findings of the Call for Evidence during our study.

Implications for strike prices

A key component of the Government's Electricity Market Reform programme is the introduction of a new support scheme for low-carbon generation based on Contract for Difference Feed-in Tariffs (CfD FiTs). These are intended to provide fixed electricity revenue to generation projects and hence make them more attractive for a wider pool of investors (by significantly reducing electricity market risk). A qualifying generator will enter into a Contract for Difference with a central counterparty, and payments will be made between the two parties based on the difference between a pre-defined 'strike price' and the prevailing electricity price (as represented by a defined market reference price).

CfD FiTs will essentially be available for nuclear, CCS, and renewable technologies. Strike prices will vary by technology. They will initially be 'administered prices', (meaning set by the government based on its view of technology costs) but the intention is that later they will be set through a competitive price discovery process such as auctions, at least for some technologies.

Projected strike prices

We derive projections for CfD strike prices required to bring forward low-carbon technologies in accordance with our deployment projections and based on our technology cost distributions. Given the significant uncertainties associated with both of these, the strike prices we derive are also highly uncertain.

Strike prices are derived for each year and each technology based on the levelised cost of projects commissioning in that year. For nuclear, CCS, and biomass conversions, our timelines already make assumptions about which projects are deployed and so deriving strike prices from the cost distributions is relatively straightforward. However it is important to note that the CfD strike required for a project is not the same as its levelised cost. One reason for this is that the duration of CfD support my not be the same as the project operating life assumed in the levelised cost calculation. Another is that an adjustment may be required to offset any systematic difference between the market reference price in the CfD and the net electricity sales price realised by the generator (taking account of any 'route to market' costs).

For onshore and offshore wind there are generally more projects available in a given year than are required by our deployment timeline. In this case we build a merit order of the available projects and select from the cheapest first to meet the projected deployment.

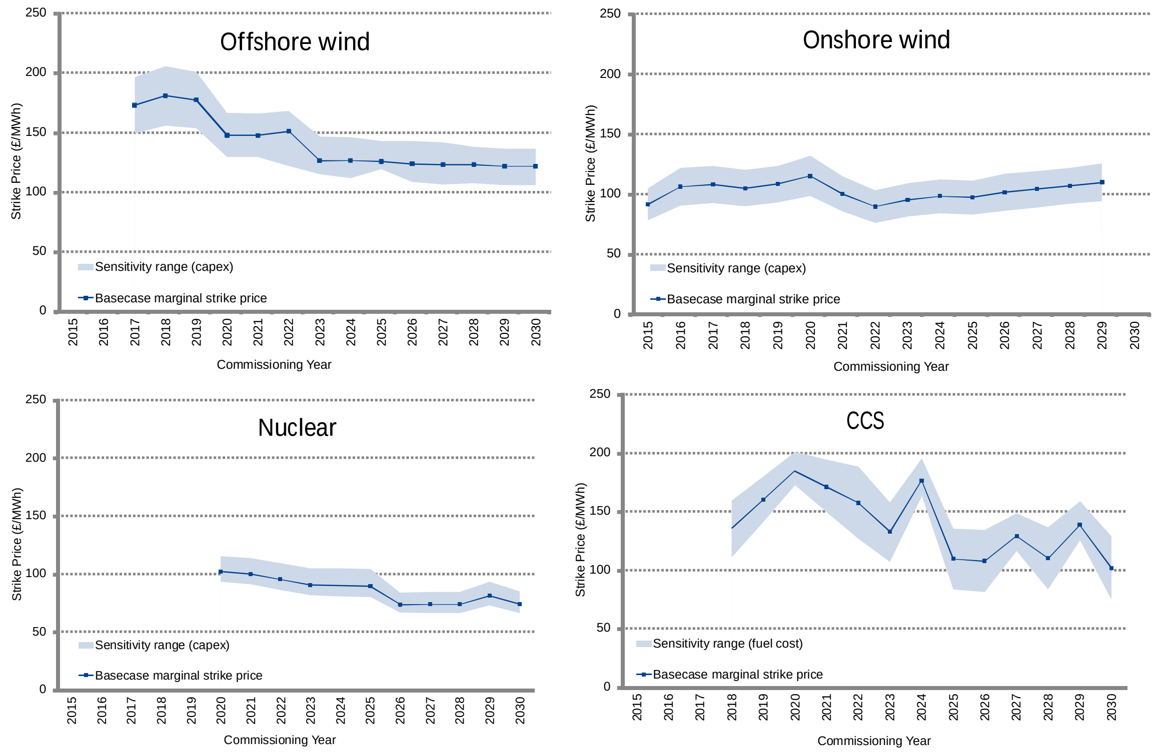
It is important to consider whether strike prices should be determined as the price required by the marginal project required to meet desired deployment, or on an individual project basis. This consideration may be different for different technologies. For offshore and onshore wind we assume that the strike price is determined as the strike price required by the most expensive project selected (i.e. the 'marginal strike price'). For CCS and nuclear we assume each project receives the individual strike price required by that project, essentially reflecting the range of different sub-technologies available in order to avoid the risk of foreclosing some technology options and/or over-subsidising other.

Figure 1 shows the range of strike prices we have derived for each of the low-carbon technologies. The uncertainty around strike prices highlights the difficulty of determining strike prices through an administrative price-setting process, and hence the desirability of moving to competitive price discovery as soon as possible. We believe that onshore wind, offshore wind, and biomass conversions all offer the potential for competitive price discovery owing to the number of projects in each pipeline.

The general trend is for strike prices to fall over time as a result of falling levelised costs (resulting from technology learning and/or reduced rate of return requirements by investors as the technology matures and is perceived as less risky). However this trend is qualified in places as follows:

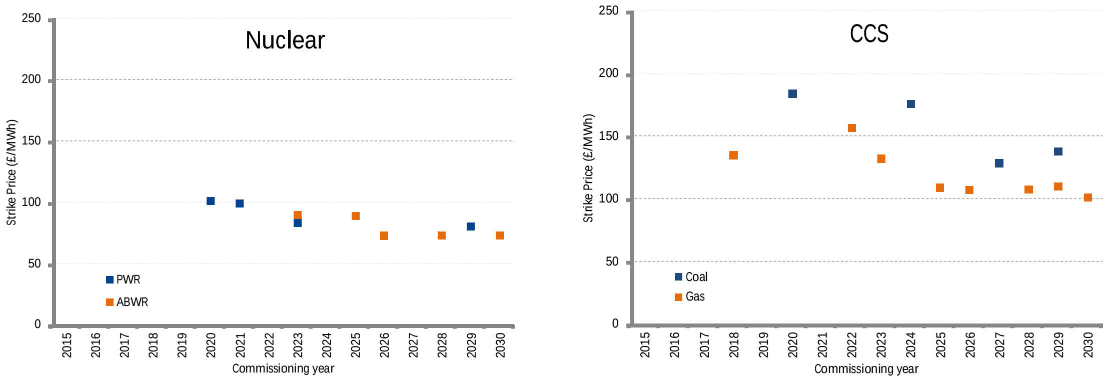
- For onshore wind, higher levels of deployment may only be achievable with rising future strike prices in the longer term as the availability of the better (i.e. cheaper) sites declines.
- For nuclear and (especially) CCS, different sub-technologies have different costs structures and this leads to more variation in strike prices assuming that different strike prices are determined for different sub-technologies. For example, Figure 2 shows strike prices differentiated by reactor type for nuclear and by fuel type for CCS (although other methods of differentiation may be appropriate – for example by capture technology for CCS).

Figure 1 – Range of derived strike prices (£/MWh, 2012)



Notes
1) The strike prices shown for a given commissioning year represents the price awarded to projects which commissioning in that year.
2) The dark blue line represents strike prices derived based on our central cost assumptions. The pale blue range shows the range of strike prices corresponding to the largest variations observed in our sensitivity analysis.
3) The strike price shown for a given year is the strike price required by the most expensive project commissioning in that year according to our deployment timeline. Hence the variability in the CCS chart stems from different sub-technologies commissioning in different years.
4) The strike prices shown for offshore wind are based on our lower deployment scenario.
5) Biomass conversion is not shown as all conversion happen in the space of a small period – see main report.

Figure 2 – Differentiated strike prices for nuclear and CCS (£/MWh, 2012)



Notes

1) The strike prices shown for a given commissioning year represents the price awarded to projects which commission in that year.
2) Based on our central cost assumptions only
3) Gas CCS includes both pre and post-combustion capture projects. Coal CCS includes both oxyfuel and post-combustion capture projects.

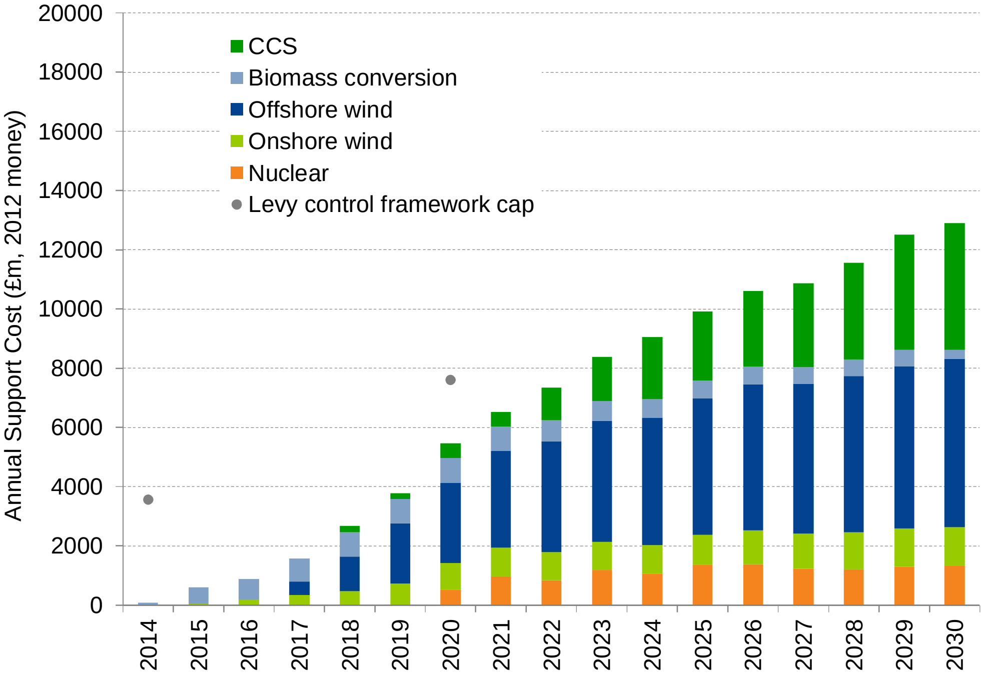
Projected support and resource costs

Figure 3 shows the total support costs we have derived for our projected deployment of low-carbon generation, based on our central cost assumptions and lower offshore wind deployment scenario, whilst Figure 4 shows projected resource costs. The latter are assessed against an assumption for the long-run marginal cost of gas CCGT generation, and represent the 'net' support cost taking account of the fact that deployment of low-carbon generation is expected to lead to lower wholesale electricity prices than would otherwise be the case. Figure 5 shows the evolution of support costs per MWh of low-carbon generation contributed by each technology.

Total support costs rise over time as low-carbon deployment increases, but the cost per MWh declines as technology costs reduce over time. Resource costs stabilise in the 2020s as the increasing deployment of low-carbon generation reduces the need for new gas-fired generation and hence suppresses wholesale electricity prices.

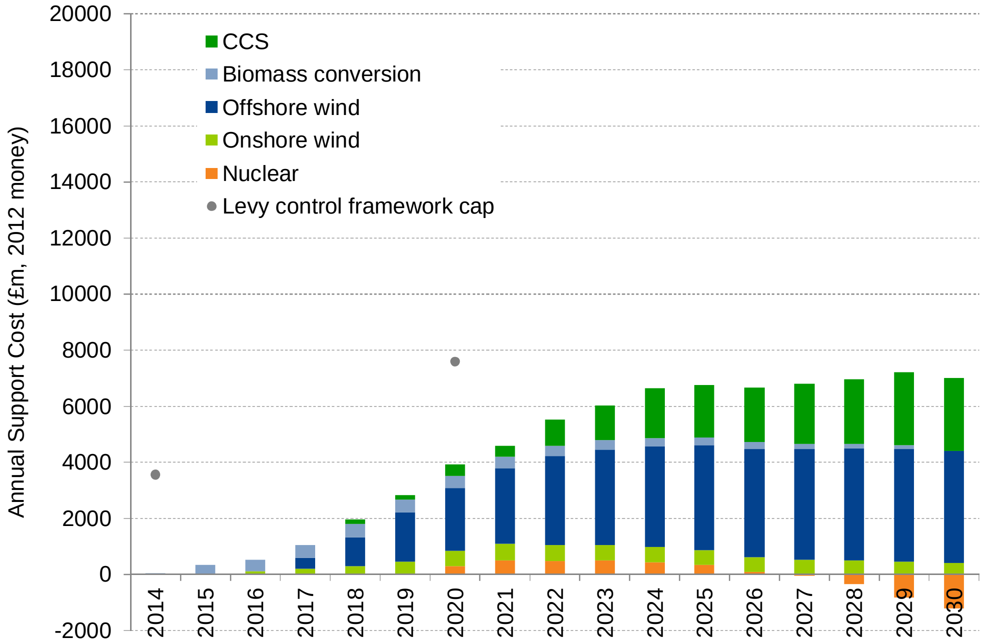
Our projections of required support costs are broadly in line with the Levy Control Framework to 2020, but there is a risk of exceeding the LCF levels. Based on our analysis, there will be a need to increase the LCF cap beyond 2020 as the volume deployment of low-carbon generation increases, even though the required support per MWh decreases. The difference between support costs and resource costs raises the question of how the Levy Control Framework cap should be defined.

Figure 3 – Projected CfD FiT support costs (base case cost assumptions, lower offshore wind deployment scenario) (£m 2012)



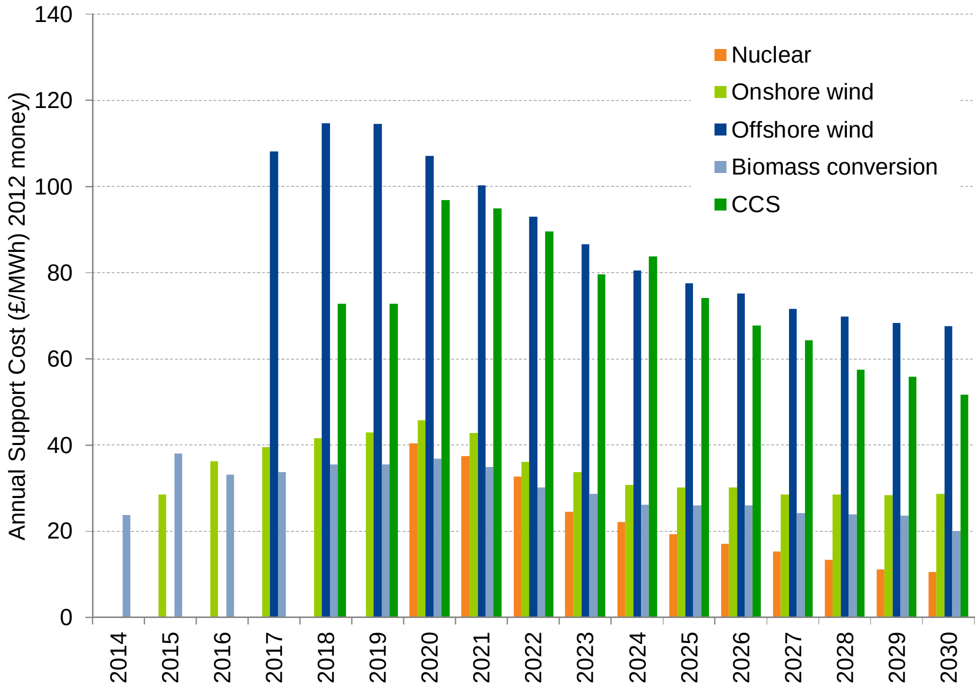
Note that the Levy Control framework caps refer to financial years 2014/15 and 2020/21, whereas support costs are shown on a calendar year basis. Support costs relate to CfD FiTs only and do not include support under the Renewables Obligation or small-scale Feed-in Tariff scheme.

Figure 4 – Projected CfD FiT resource costs (base case cost assumptions, lower offshore wind deployment scenario) (£m 2012)



Note that the Levy Control framework caps refer to financial years 2014/15 and 2020/21, whereas support costs are shown on a calendar year basis. Support costs relate to CfD FiTs only and do not include support under the Renewables Obligation or small-scale Feed-in Tariff scheme.

Figure 5 – Support costs per MWh (base case cost assumptions, lower offshore wind deployment scenario) (£/MWh 2012)



Annual support cost per MWh is calculated as total support cost for a given technology in a given year, divided by the volume of electricity delivered in that year

Looking beyond 2030

Although this study focuses on deployment of low-carbon technologies out to 2030, this date is itself a milestone on the path to the UK's 2050 carbon goals. The longer term deployment of these technologies will depend on:

- **The overall potential of the technology** – Government action may be required to realise this potential, for example new offshore licensing rounds or identification of new nuclear sites.
- **The status of the supply chain in 2030** – and hence its ability to deliver further deployment thereafter. If our deployment projections to 2030 are achieved, then technologies such as offshore wind, nuclear, and CCS will be well placed to continue the capacity growth beyond 2030 that will be required to meet the 2050 goals. If deployment of a technology by 2030 falls short of our projections, then faster growth rates will be required beyond 2030 to 'catch up'. However, in this case the ability to ramp up capacity in the 2030s could be impaired (compared to the case where 2030 deployment projections are achieved) by a lower level of industry experience or a less well developed supply chain at that point.

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1. INTRODUCTION

1.1 Background

The Committee on Climate Change is tasked with providing advice to government on climate change issues, and particularly the setting of carbon budgets for the UK. The Climate Change Act requires the Committee to report annually to Parliament on progress towards meeting these budgets. The fourth carbon budget legislated in June 2011 requires that the UK must reduce emissions in 2025 by 50% relative to 1990 levels. This budget is designed to move the UK onto a path towards hitting the legal target to reduce emissions by at least 80% in 2050 relative to 1990.

Decarbonisation of the electricity generation sector will play an important role in meeting the UK's carbon budgets. To achieve the target set out in the fourth budget, the Committee has proposed several scenarios for the evolution of electricity generation in order to achieve a grid carbon intensity of around 50gCO_2/kWh in 2030. These scenarios depend on an extensive roll-out of renewables, nuclear and fossil-fuelled plants fitted with carbon capture and storage (CCS). The challenge of achieving generation emissions of 50gCO_2/kWh is significant due to the price premium associated with low-carbon technologies compared with the lowest cost generating alternative (at least in the nearer term). As this premium is ultimately born by UK consumers, the Government is concerned that low-carbon technologies should be deployed in as cost-effective manner as possible whilst still meeting the UK's carbon budgets and other goals (including the 2020 renewables target under the Renewable Energy Directive).

The Government's Electricity Market Reform (EMR) package is designed to meet these objectives. One element of this – the Carbon Price Floor – has already been introduced, whilst the remaining measures are included in the Energy Bill which is expected to be enacted later this year. A key component of EMR is the introduction of a new support scheme for low-carbon generation based on Contract for Difference Feed-in Tariffs (CfD FiTs). These are intended to provide fixed electricity revenue to generation projects and hence make them more attractive for a wider pool of investors (by significantly reducing electricity market risk). A key goal of EMR is to encourage new sources of capital into the UK electricity sector in order to finance the significant level of investment required to decarbonise electricity.

CfD FiTs will be available for nuclear, CCS, and renewable technologies. A qualifying generator will enter into a Contract for Difference with a central counterparty, and payments will be made between the two parties based on the difference between a pre-defined 'strike price' and the prevailing electricity price (as represented by a defined market reference price[3]). If the strike price exceeds the market reference price then the central counterparty pays the difference to the generator; if the market reference price exceeds the strike price then the difference payment flows in the other direction. At the same time the generator sells its output in the wholesale electricity market, such that the aggregate of this sales revenue and the difference payment delivers fixed revenue[4].

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3 There will be different reference prices for intermittent and baseload generators.

4 There may be some 'basis risk' if the sales price achieved by the generator in the electricity market does not match the market reference price. This is likely to be small in comparison with overall electricity price fluctuations (but will still have a cost associated with it – see Section 4.1).

The strike price will vary by technology. They will initially be 'administered prices', (meaning set by the government based on its view of technology costs) but the intention is that later they will be set through a competitive price discovery process such as auctions, at least for some technologies. Establishing an appropriate strike price for each low-carbon technology will be crucial for delivering the carbon reduction targets. If strike prices are set 'too low' then insufficient generation may come forward, but if they are set 'too high' then the support cost imposed on UK consumers will be higher than necessary. The appropriate strike price for a given technology will depend on the overall cost of that technology (including providing reasonable returns to investors).

However, for a given technology, the cost of generation will vary from project to project and may also vary with time. Hence, in order to understand the level of financial support required to achieve low-carbon targets, it is necessary to understand the distribution of technology costs across the supply of potential projects and also how this supply curve might vary over time. The overall costs of decarbonisation of electricity provision will also depend on the relative contribution of different low-carbon technologies. Hence it is also important to develop a view of how the deployment of each technology may develop over time.

1.2 Objectives

The aim of this study is to update the Committee's view of the potential deployment of five key low-carbon electricity technologies expected to make significant contributions to decarbonising the electricity sector by 2030, to update its view of the costs of these technologies, and to understand what levels of support might be required to achieve this deployment.

1.3 Overview of methodology

This section provides an overview of our methodology. More detail is provided in subsequent chapters.

The technologies considered within the scope of the study are:

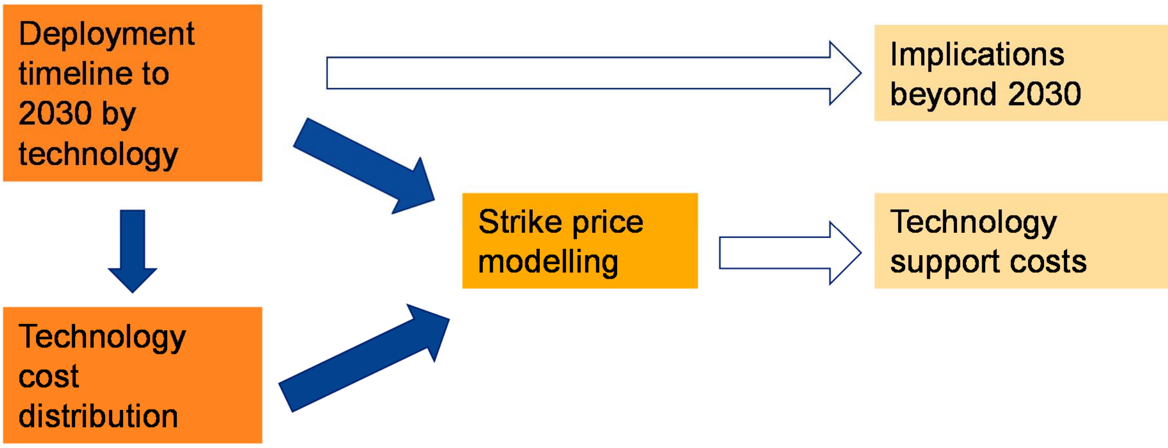
- onshore wind;
- offshore wind;
- nuclear;
- CCS (based on gas or coal); and
- biomass conversion – i.e. conversion of existing coal fired generating units to run 100% on biomass.

These were selected by the Committee as the grid-scale electricity generation technologies likely to make the most significant contributions to meeting medium term carbon budgets (out to 2030) as well as the 2020 renewables target.

Our approach is summarised schematically in Figure 6. The three main stages are derivation of feasible deployment timelines, derivation of cost distributions, and calculation of implied strike prices. In addition we compare the required support costs (and associated resource costs) implied by these strike prices is consistent with the Levy

Control Framework[5], and also the implications of the deployment picture to 2030 for the UK's longer term carbon goal (of an 80% reduction by 2050).

Figure 6 – Schematic representation of methodology



1.3.1 Deployment timelines

First, we develop feasible 'timelines' for each technology. By 'timeline' we mean an outlook of how the project pipeline might develop over time taking into account the different stages of project development (such as consenting, construction, operation). The aim is to understand the existing project pipeline, what deployment might be achieved by 2030, what are the key factors limiting deployment, and what policy 'enablers' might be available or required to mitigate these limitations. In general our timelines are 'high effort' deployment scenarios – meaning that we assume a continued commitment from the Government to achieve its carbon goals and hence a willingness to implement policies to support the significant growth of low-carbon generation required.

To derive these timelines we examine the existing evidence base of published studies. We supplement this where appropriate with input from our in-house expertise, which stems from our experience of providing both technical and economic advice across all of the selected technologies. Finally, the Committee organised a series of stakeholder seminars for the different technologies, allowing us to benefit from the detailed knowledge of industry experts.

As well as defining a plausible deployment path to 2030, these timelines allow us to reflect qualitatively on the implications for further decarbonisation beyond 2030 in respect of each technology (see Chapter 5).

1.3.2 Cost distributions

Second, we derive a cost distribution (or 'supply curve') for each technology showing the potential volume of low-carbon electricity available and the cost of developing this. Costs are expressed as the levelised cost of electricity (LCOE) (in £/MWh), taking account of

5 The Levy Control Framework is a Government (Treasury) limit on the costs of certain DECC policies (whether these are funded directly by Government or by consumers). It is intended to ensure that the UK meets its energy and climate goals in a manner which is affordable in the context of wider economic goals and consumer bills.

capital and operating costs and assuming the generator will require a specified rate of return on its investment.

For nuclear, CCS, and biomass conversion our approach is to review the existing evidence base on costs and generally use the latest evidence available. However we use our in-house expertise to fill in any gaps where this evidence is incomplete. The project pipelines for all of these technologies are characterised by a relatively small number of discrete large projects, and we map costs from the evidence base onto specific projects to derive a detailed supply curve in each case. Using the deployment timelines described above, we are able to incorporate any changes to costs over time (for example resulting from technology learning or de-risking effects).

For onshore and offshore wind we adopt different approaches. In each case there is a relatively large number of projects in the pipeline (compared to nuclear, CCS, and biomass conversion), and the existing published evidence base is not sufficiently detailed to allow the construction of a detailed supply curve which captures the full range of projects.

For offshore wind we undertake a bottom-up costing of all of the undeveloped projects for which The Crown Estate has awarded licences – these include Round 3 projects, Scottish Territorial Waters projects, and Round 2 projects (and Round 1 or 2 extensions) which have not yet reached financial close[6]. This approach allows us to better capture cost differences between projects arising through the various cost drivers such as geographic location, water depth, distance from shore, and turbine size.

For onshore wind the very large number of projects means that it is not practical in this study to assess costs for individual projects. Instead we have modelled a supply curve based on a defined number of typical project types, characterised by project capacity and distance from grid[7], and derive costs for each project type[8]. We then assign the onshore wind project pipeline to these project types based on public information about their size and location. We also use location data to further disaggregate the project pipeline by reflecting different load factors and grid charges for different geographic zones. This approach allows us to develop a detailed supply curve reflecting a range of project sizes and locations.

1.3.3 Strike price modelling

We then use the cost distributions to assess the level of CfD strike prices likely to be required for each technology to bring forward deployment in line with the projected deployment timeline. To do this we develop a modelling tool which:

- calculates the strike price which each potential given project would require to earn its desired return; and
- selects from the potential projects available in each year to meet the timeline deployment for the year, based on the cheapest projects first.

For nuclear, CCS, and biomass conversions, our timelines already make assumptions about which projects are deployed and so deriving strike prices from the cost distributions

6 Where licensed zones will be developed in phases we have considered each phase as a separate project.

7 These were considered to be two key drivers of onshore wind costs.

8 See Section 3.3.1 for further details.

is relatively straightforward. However it is important to note that the CfD strike required for a project is not the same as its levelised cost. One reason for this is that the duration of CfD support my not be the same as the project operating life assumed in the levelised cost calculation. Another is that an adjustment may be required to offset any systematic difference between the market reference price in the CfD and the net electricity sales price realised by the generator (taking account of any 'route to market' costs).

For onshore and offshore wind there are generally more projects available in a given year than are required by our deployment timeline. In this case we build a merit order of the available projects and select from the cheapest first to meet the projected deployment. For these technologies we assume that the strike price is determined as the strike price required by the most expensive project selected (i.e. the 'marginal strike price'). This is consistent with the objective of determining strike prices through competitive price discovery[9].

Knowledge of the strike prices required to achieve the deployment timeline for each technology then allows us to evaluate the level of support required in the form of CfD difference payments.

1.4 Limitations to the study

It is important to understand the limitations of a study of this nature, especially given the ambitious objective of examining the cost and deployment evolution of five different low-carbon technologies out to 2030. These limitations derive both from the limited time and budget available for the study and from the inherent uncertainties in considering how the future might evolve:

- The number of technologies and large number of potential projects within each technology limits the level of detail we can apply in assessing the cost of each. Whilst an objective of this study was to look at cost in more detail than many recent studies, and in particular to capture the distribution of costs across the project pipeline, we have had to make some simplifications. For example we have grouped onshore projects into categories rather than look at each project individually.
- We have drawn on the existing evidence base in a number of areas rather than perform primary research. Although we have used our in-house expertise to update or add to this in certain areas, in other areas it has not been feasible to do so. Whilst this evidence base (typically previous studies commissioned by DECC or the Committee) is robust and credible, it may in some cases be slightly out of date or lack the level of detail needed for this study.
- Perhaps most importantly, there will always be uncertainty associated with a study addressing future developments. For technology costs there is the uncertainty associated with costing a project today – for example engineering feasibility studies will typically quote a wide uncertainty range on capital cost estimates. This is especially so for less mature technologies such as CCS or the next generation of nuclear stations, where there are few or no existing projects. There is also uncertainty in future operating costs, in project lifetime, and in the rate of return required by investors. These uncertainties are compounded by uncertainty about how all of these cost components might change over time as a technology matures.

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9 However the reality of how CfDs are allocated, at least in the early years, is likely to be more complex than this, and the CfD strike price available may be different from this.

- On the deployment side there is uncertainty about which projects might proceed and when. For nuclear, CCS, and biomass conversion we have made assumptions about which projects or sub-technologies might go forward. Similarly for wind we have made assumptions about the future pipeline of onshore projects and about how offshore developers may develop their licence areas. Whilst our assumptions are informed by public information wherever possible the actual outcome may clearly be different.

As a result of these limitations and uncertainties, the results presented here should not be regarded as firm predictions of the future. They should be viewed as illustration of what might happen to deployment given certain conditions, or what strike prices might be required based on the costs we derive. To put this uncertainty into context we have performed sensitivity analysis to understand the impact of uncertainty in key cost drivers on required strike prices. We present our derived strike prices as ranges based on what we consider is the possible range of values for the largest single driver of cost uncertainty for each technology. However the range of possible strike price outcomes could be wider than the ranges we present as a result of uncertainty in all of the cost drivers.

1.5 Structure of this report

This report is structured as follows:

- Chapter 2 shows the deployment timeline developed for each low-carbon technology;
- Chapter 3 describes the development of the cost distributions for each low-carbon technology;
- Chapter 4 describes the results of our strike price analysis for each low-carbon technology, including the required support costs; and
- Chapter 5 describes the implications of the timelines developed in Chapter 2 for further deployment of each low-carbon technology beyond 2030.

1.6 Conventions and glossary

- All monetary values quoted in this report are in pounds sterling in real 2012 prices, unless otherwise stated.
- Annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified.
- Plant efficiencies throughout this report are defined at the Higher Heating Value (HHV) basis. Fuel prices are similarly quoted on a gross (HHV) basis.
- Unless otherwise stated, all discount rates and rates of return are expressed on a pre-tax real basis, and as a project return (before consideration of the debt and equity structure).

1.6.1 Sources

Unless otherwise attributed the source for all tables, figures and charts is Pöyry Management Consulting.

1.6.2 Bibliography and acronyms

Annex C provides a list of published studies used as the evidence base for this study. Where applicable these are referenced in the text through footnotes, whilst Annex D provides definitions of various acronyms used this report.

1.7 Acknowledgements

We would like to acknowledge the assistance of a number of parties in performing the study:

- relevant staff at the Committee on Climate Change secretariat;
- various in-house engineering experts at Pöyry; and
- all attendees at the stakeholder workshops organised by the Committee to discuss some of our initial findings on deployment outlook and costs.

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2. CONSIDERING FEASIBLE DEPLOYMENT TIMELINES

In this chapter we examine the outlook for deployment of each of the five low-carbon technologies. In each case we present a timeline presenting our view of how deployment could develop, assuming a policy environment which remains consistent with meeting the UK's climate goals.

By 'timeline' we mean an outlook of how the project pipeline might develop over time taking into account the different stages of project development (such as consenting, construction, operation). The aim is to understand the existing project pipeline, what deployment might be achieved by 2030, what are the key factors limiting deployment, and what policy 'enablers' might be available or required to mitigate these limitations.

In general our timelines are 'high effort' deployment scenarios – meaning that we assume a continued commitment from the Government to achieve its carbon goals and hence a willingness to implement policies to support the significant growth of low-carbon generation required.

2.1 Methodology

Section 1.3.1 describes our general approach. The starting point for each timeline is the status of the current project pipeline. We then consider how this might evolve over time, taking into account previous deployment studies, our own views, and comments from industry stakeholders.

Each timeline should be regarded as an illustration of what might happen if appropriate policies are in place to encourage investments in each technology, rather than as firm predictions of the future. However constructing timelines in this fashion enables a deeper understanding of what are the key issues for each technology and hence identifying what further policy enablers might be required.

Note that our timelines are constructed with a view to assessing what level of capacity might be operational by 2030 for each technology. We do not consider what level capacity might be at the other various stages of development at this point.

2.2 Offshore wind

2.2.1 Overview of project pipeline

The Government sees offshore wind as playing an important role in meeting the UK's renewable and climate change targets, and in recent years has introduced a number of measures to encourage its development. As a result, the UK now had (in January 2013) around 2.7GW of offshore wind in operation and 1.5GW under construction, with a further 2.3GW having received planning consent[10]. The Crown Estate has granted leases through its various licensing rounds for a total of around 47GW of capacity[11].

When considering potential deployment out to 2030 we consider all existing and potential future projects. However when considering project costs and strike prices needed to

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10 These figures represent a snapshot of Renewable UK's Wind Energy Database taken in January 2013.

11 This figure includes sites already in operation, under construction, or consented.

bring projects forward we consider only the pipeline of potential future projects, which we define as all projects which we considered to be 'uncommitted' at the end of 2012. Specifically this includes:

- all Round 3 projects;
- all Scottish territorial Waters projects; and
- a number of Round 2 and extension projects[12].

Where developers have indicated that they will develop a licence zone in stages, we have treated each phase as a separate project. Thus our future pipeline totals 64 projects totalling around 40GW.

2.2.2 Factors affecting deployment timescales

The rate of deployment of offshore wind will depends on a number of factors. These factors could act as constraints limiting the rate at which new projects are developed.

Availability of sites and development leases

The Crown Estate (and the Government more widely) strongly supports the development of offshore wind, as evidenced by the issuance of development leases for around 47GW of capacity to date. To put this into context, the 2011 Renewable Energy Roadmap suggests a central range of 11-18GW by 2020[13]. There are sufficient leases to allow for a very aggressive expansion of offshore wind capacity, even allowing for some project attrition (for example if sites fail to achieve planning consent or prove unsuitable for other reasons). Furthermore it is likely that The Crown Estate would hold further leasing rounds should it appear that further sites are required. Hence we do not believe availability of sites is a constraint on offshore wind development.

Consenting

Like other large power stations, offshore wind farms are required by Section 36 of the Electricity Act to obtain development consent from the Planning Inspectorate. The Inspectorate aims to determine consent applications in 16 months, although the developer will also spend a significant time before submitting an application in preparing the documents required (such as an Environmental Impact Statement).

Although the Government is generally supportive of offshore wind, it is possible that individual consent applications may be rejected for site specific reasons. For example in 2012 consent was refused for Docking Shoal. However, most projects to date have successfully received consent[14]. Hence we believe consenting is not a major barrier for offshore wind in aggregate, although it may be an issue for specific projects.

The time taken to prepare a consent application and for it to be determined will have an impact on the date by which projects can come on line. For example many of the Round 3 developers are now at the stage of preparing and submitting consent applications for the first projects in their zones. Allowing for the time taken to reach financial close following

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12 Specifically Westernmost Rough, London Array (Phase 2), Dudgeon, Race Bank, Triton Knoll, Galloper, Kentish Flats 2, Burbo Bank Extension, and Walney Extension.

13 DECC (2011a)

14 The UK Renewable Energy Roadmap (DECC 2011a) suggests a 7% project dropout rate, whilst the 2012 update to this (DECC 2012) suggests 3%.

granting of consent, and the time for construction, this means the first Round 3 projects are unlikely to be available for commercial operation before the latter part of this decade.

Supply chain capability

One potential limitation on the rate of deployment of offshore wind farms is the capacity of the various supply chain components needed for construction. These components range from wind turbine manufacturing capacity, availability of installation vessels, and suitable port infrastructure. Given that offshore wind is a relatively new industry, building up the supply chain has been a significant challenge and will continue to be such if deployment rates are to increase further. This includes the need to build up O&M capability to support wind farms once operational.

Offshore wind is not just a UK industry, and some elements of the supply chain (such as wind turbine supply) need to be considered in a European or even global context as several other countries have significant offshore wind ambitions. This may allow the establishment of a larger, more robust, supply chain, but at the same time means that UK projects may be competing with other countries for supply chain capacity.

There have been several studies looking at this issue. For example, the UK Offshore Wind Cost Reduction Taskforce concluded that a deployment rate of 2GW/yr by 2020 is possible in its central 'Supply Chain Efficiency' story (with 3GW/yr in the Rapid Growth scenario)[15]. BVG also suggest around 3GW is possible[16]. In a number of studies, BVG has looked at what might be the main bottlenecks in the supply chain[17].

Availability of finance

The availability of finance may also be considered as a 'supply chain' issue, although we discuss it separately here. Offshore wind is very capital intensive compared to many other electricity generation technologies, with a capital cost typically around £3,000/MW. This means there is a significant requirement for funding. Whilst funding is required at all stages of the project lifecycle – development, construction, and operation – the main funding requirement commences once construction begins following the main financial investment decision.

Most offshore wind projects to date have been financed by utility developers using their balance sheets perhaps with some project finance debt. However, there is a limit to the amount of balance sheet capital which the major European utilities who have offshore wind leases may be able to provide, given that many of these are looking to rebuild their balance sheets and/or are looking to make many other major investments at the same time. Once a project is operational the developer may look to sell some of its equity in order to raise capital for the next project – we have seen a number of such transactions in the UK recently. Nevertheless, availability of construction finance is still perceived as a key issue for offshore wind and possibly the limiting constraint at present[18]. Whilst longer term finance during operation may also be an issue, there is likely to be a larger pool of investors willing to provide capital for this less risky (relative to construction) phase of the project.

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[15] EC Harris (2012)

[16] BVG (2011)

[17] BVG (2009), BVG (2011), BVG (2012)

[18] Baringa (2012)

The UK Offshore Wind Cost Reduction Task Force looked at the issue of availability of finance in detail[19]. It identified a potential shortfall in the required funding available, particularly before 2020, resulting in a need to offer higher returns to attract new sources of capital.

Government appetite

One factor which could constrain offshore wind deployment is Government ambition. The 2011 Renewable Energy Roadmap[20] included deployment scenarios ranging from 11GW to 18GW by 2020, contributing to meeting the EU Renewable Energy Directive target. Beyond 2020 there is no target for renewable energy, but offshore wind is expected to play an important role in meeting climate change targets beyond then. Compared to some other low-carbon technologies, offshore wind current requires relatively high levels of financial support. It is anticipated that the cost (per MWh) of support required for offshore wind will reduce over time as the industry matures, but if costs don't fall as expected then the Government may wish to limit the support burden to consumers and this in turn could constrain deployment.

The Government has already effectively set a limit on financial support costs for all low-carbon technologies, through the Levy Control Framework. This could act as a constraint on deployment before 2020, as offshore wind is expected to account for a large share of these support costs before 2020 (see Section 4.8).

Grid integration

There are significant challenges in accommodating large volumes of intermittent generation capacity on electricity networks. This issue has been addressed extensively elsewhere and is outside the scope of this study[21]. Clearly any significant deployment of offshore wind is conditional on successfully addressing this challenge, perhaps through increased interconnection with Europe, development of electricity storage technologies, or increased flexibility of both demand and other forms of generation.

2.2.3 Deployment timelines to 2030

The future deployment path of offshore wind to 2030 is uncertain. Given the large potential capacity for which leases have already been awarded, and the expectation that consenting will not be a major barrier for the vast majority of this capacity, factors which will determine the scale of deployment will be the capacity of the industry to develop projects (both in terms of supply chain capability in general and availability of finance in particular), and the availability of support in the form of CfD FiT contracts.

We examine this uncertainty by presenting two possible deployment paths (see Table 3). We have labelled the first the 'lower deployment' scenario, although it still implies a significant growth in offshore wind capacity. The higher deployment scenario considers the possibility of a very high deployment of offshore wind by 2030.

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19 PWC (2012)

20 DECC (2011a)

21 See for example Pöyry (2010)

Table 3 – Lower and higher offshore wind deployment scenarios

	Lower deployment	Higher deployment
Installed capacity in 2030	25GW	40GW
Availability of CfD support	Limited to 25GW	Not limited
Maximum deployment rate	1.6GW/yr	2.8GW/yr

In the lower deployment scenario we have limited overall deployment to 25GW by 2030. This was based on scenarios developed by the Committee for its Renewable Energy Review, which suggested that higher levels of deployment should be considered only if the costs of offshore wind reduce significantly. Given this ambition, we assume deployment to 2030 develops in a smooth manner to avoid stop-start investment in supply chain capacity. The resulting required supply chain and finance capacity is up to 1.6GW/yr, which we believe is achievable based on our review of the evidence base. In this scenario, deployment is limited by availability of CfD support rather than supply chain and finance capability.

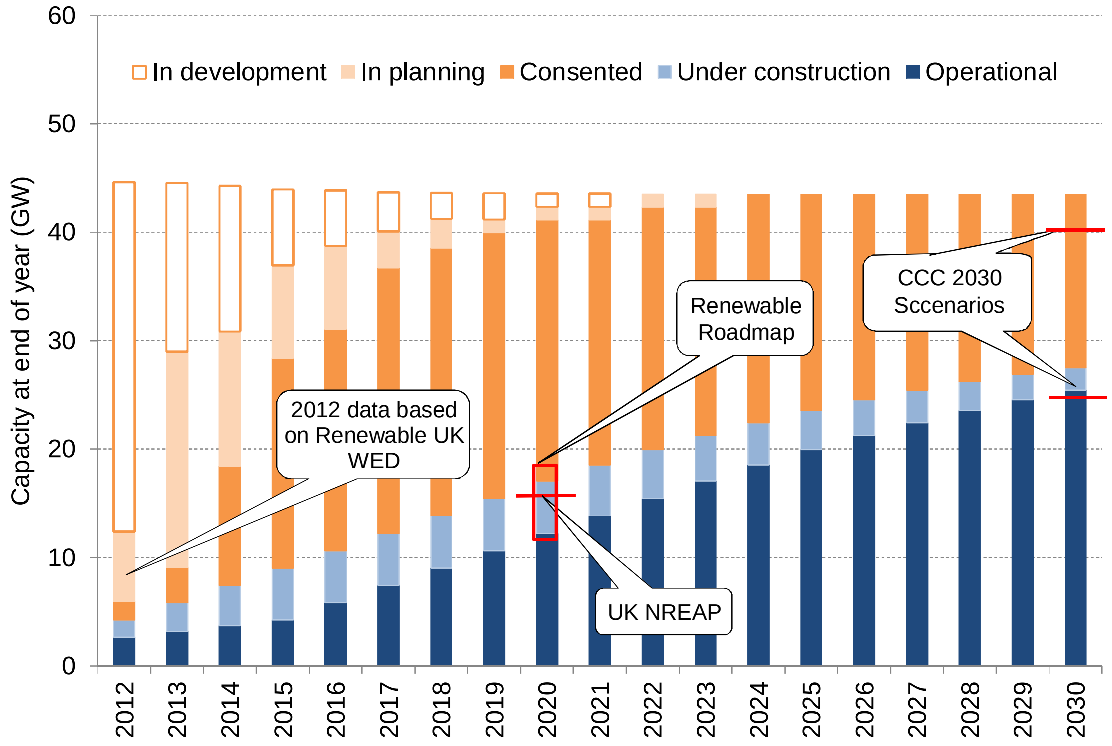
Our higher deployment scenario assumes that costs have decreased significantly, to the extent that deployment is more likely to be constrained by supply chain and finance capability rather than by government support. In this scenario maximum annual deployment is just under 3GW/yr, and total installed capacity reaches 40GW in 2030.

2.2.3.1 Lower deployment scenario

Figure 7 shows our suggested deployment outlook for offshore wind in our 'lower case' scenario. Each column shows the projected capacity at each stage of development at the end of the calendar year. The 2012 column shows our view of the existing pipeline at the end of the year, based on Renewable UK's Wind Energy Database[22].

[22] www.renewableuk.com. Note that total size of the pipeline does not exactly match the licensed capacity of all licence rounds because in some cases we have taken the view that not all of the licenced capacity will be developed, based on announcements from developers.

Figure 7 – Offshore wind timeline (lower deployment)



In the short term our timeline shows a significant increase in the capacity entering the planning system and then gaining consent, comprising the early Round 3 projects plus many of the remaining projects from earlier rounds. This is based on information from the Planning Inspectorate and from developers' own websites. For later projects the date of consent application is not known and we have had to make assumptions – where a licence zone is expected to be developed as several large projects, we assume a staggering of consent applications (typically two year intervals).

Despite this ramp up in applications, we assume that all applications are determined in the 16 month period specified by the Planning Inspectorate, as one would expect that a Government committed to offshore wind would ensure the Planning Inspectorate is sufficiently resourced to achieve this. We assume an attrition rate of 3%[23], comprising projects which do not proceed to submitting a consent application or for which consent is refused.

Once a project is consented, the next stage is to proceed to financial close. This entails securing a number of project agreements (e.g. a construction contracts, a power purchase agreements and CfD FiT, and an O&M contract) as well as sufficient finance for construction. We see the achievement of financial close as the limiting constraint for offshore wind, limited by the availability of construction finance.

We assume that between now and 2020 a maximum of 1.6GW reaches financial close in any year. Assuming a three year construction period, the operational capacity reaches around 12GW in 2020. This is slightly below the level suggested in the UK's National

23 DECC (2012)

Renewable Energy Action Plan (NREAP)[24] and at the lower end of the range implied by the Renewables Roadmap[25]. It is also broadly consistent with the lowest deployment story developed by the UK Offshore Wind Cost Reduction Task Force. Hence we believe this level of deployment is plausible assuming a continuation of the current policy commitment.

In this scenario we assume around 25GW of installed capacity by 2030. This is consistent with one of the scenarios developed by the Committee for its 2011 Renewable Energy Review[26], and is consistent with the view that further deployment beyond this should not be supported unless the costs of offshore wind fall significantly. A consequence of this is that in our timeline the assumed rate of construction declines slightly year on year during the 2020s as this limit is approached. However, the supply chain built up by the early 2020s will have the ability to deliver more capacity (see Section 2.2.3.2 below).

One feature of the way we have constructed our timeline is that a large volume of capacity is consented before 2020 but is not built until much later, if at all, owing initially to the constraint on construction finance and later to the limit on Government support for offshore wind. In reality it is possible that developers may defer applications for consent for some projects if it is not clear that the project will be able to proceed shortly after gaining consent. Where a developer has several licences they may choose to prioritise one area above another. On the other hand, it does suggest that the volume of projects seeking financing and CfDs in the near term could exceed the availability of both, and this could facilitate the Government's aim of introducing competitive price discovery into setting CfD strike prices at an early opportunity.

2.2.3.2 Higher deployment scenario

In Figure 8 we present a higher deployment scenario for offshore wind, reaching around 40GW of installed capacity by 2030. This scenario might arise if the costs of offshore wind fall significantly (or if fossil fuel prices rise more than expected) such that support costs are not a constraint on deployment. Alternatively this high level of deployment might be required to meet carbon budgets if other low-carbon technologies such as nuclear or CCS do not develop as expected.

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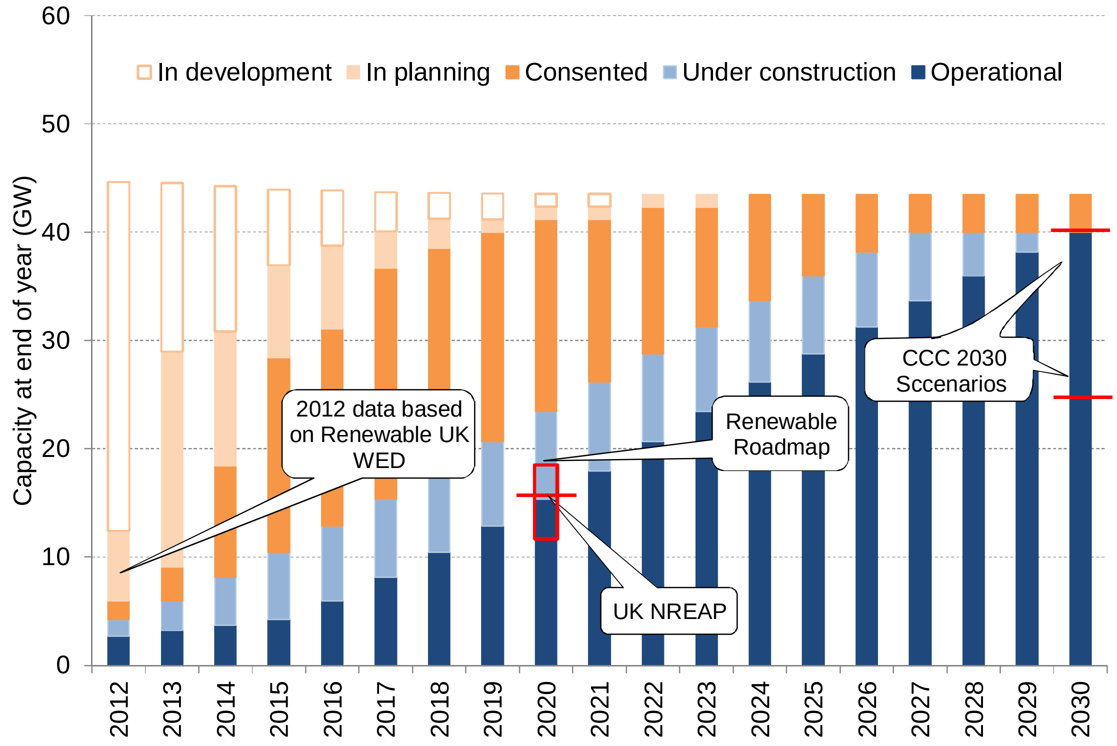
24 DECC (2010)

25 DECC (2011a)

26 CCC (2011b)

Figure 8 – Offshore wind timeline (higher deployment)



In this scenario the rate of construction starts increases steadily during the 2020s to around 3GW by 2020. This is broadly consistent with deployment pathways suggested by the UK Offshore Wind Cost Reduction Taskforce's Rapid Growth Scenario[27], BVG (for The Crown Estate)[28], and Arup's high scenario (for DECC)[29]. The limits to deployment in this case are construction finance and supply chain capacity generally. As a result the 2020 NREAP target is reached. Beyond 2020 the rate of deployment declines slightly but remains above 2GW/yr.

Our timeline does not assume new leasing rounds, but we believe these would be introduced if the rate of attrition increases such that new sites are required. We also assume that the grid can accommodate this level of offshore capacity by 2030[30].

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27 The Crown Estate (May 2012). In fact all of the scenarios developed for the study achieve an installation rate of at least 3GW/yr by 2020.

28 BVG (2012). Supply chain capacity increases to almost 4GW/yr in 2020.

29 Arup (2011)

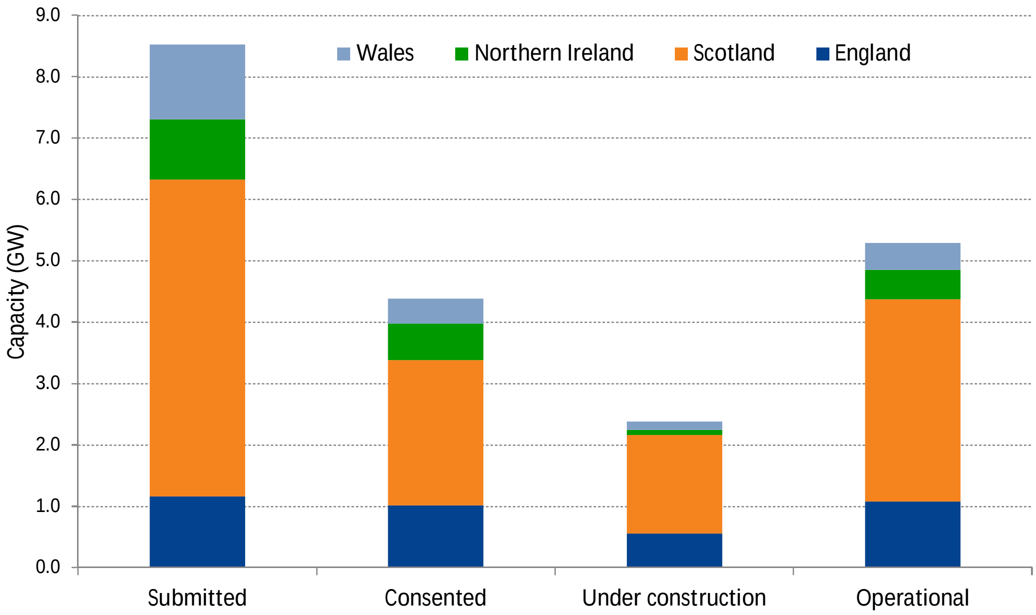
30 This question is considered in detail in our previous report for the Committee – Pöyry (2011). The higher deployment here is broadly consistent with the High scenario from the 2011 study. That study concluded that such high levels of deployment can be accommodated technically, given sufficient investment in grid flexibility.

2.3 Onshore wind

2.3.1 Overview of the onshore wind project pipeline

The current pipeline of onshore wind projects in the UK is very diverse both geographically and by project size. Figure 9 shows the current pipeline of onshore wind projects in planning[31], consented, or under construction (around 14GW in total), as well as operational projects (around 5GW[32]). Scotland is currently the most significant region in the UK for onshore wind and this is a trend that is likely to continue, based on the pipeline of future projects. The pipeline also suggests proportionally fewer projects being built in England in the short-term. This is the result of developers focusing on more lucrative sites in Scotland and avoiding the planning system in England where approval rates are consistently lower than other regions[33].

Figure 9 – Onshore wind project pipeline and current operational projects



Source: Renewable UK Wind Energy Database, snapshot taken mid-January 2013

31 "In planning" means projects which have formally submitted a planning application and are awaiting decision – this includes projects on appeal and repowering applications. "Consented" projects have been granted planning permission but are in the process of ensuring that they meet planning conditions pre-construction (such as conditions on radar interference) and/or putting in place finance.

32 Around 5.3GW was operational when we took our snapshot from Renewable UK's Wind Energy Database in mid-January 2013. By the end of April 2013 this had increased to just under 6GW. (Note that the Government's Energy Trends statistics suggest a slightly higher value of around 5.9GW of installed capacity at the end of 2012).

33 RUK (2012)

There is sufficient capacity in the current pipeline to exceed the Government's projections for onshore wind deployment in 2020, if it is all developed[34]. However, based on historic performance, it is likely that some projects in the pipeline will not be developed, for example because they fail to achieve planning consent.

2.3.2 Factors affecting deployment timescales

Government appetite

Onshore wind is expected to make a significant contribution to meeting the UK's Renewable Energy Directive target of 15% of energy being from renewable sources by 2020. The technology is mature and proven with little cost reduction envisaged up to 2020[35]. Future deployment will be contingent on changing external factors such as planning policy, government support, and grid expansion. These factors are very dependent on the progression of the priority actions set out in the UK Renewable Energy Roadmap. These priority actions could increase the number of feasible sites as investments in grid expansion and radar interference solutions are made.

Availability of sites

The number of onshore sites in the UK is potentially seen as a limiting factor to the overall deployment of onshore wind. Projects are frequently rejected on the grounds of visual impact reflecting, at least in part, that the 'best' sites in terms of reduced visual impact are increasingly being used up and developers are being forced to develop sites that will be more difficult to gain planning approval for. Other reasons for rejection include radar issues or proximity to residential areas. Additionally, as onshore wind capacity increases, multiple applications are being made in close proximity, reflecting that developers may be finding it harder to find high quality sites.

It is unclear what the ultimate limit on onshore wind deployment is as imposed by availability of sites. For example, we estimate that the UK has an onshore capacity density of around 20kW/km^2 compared with around 45kW/km^2 in Spain and 80kW/km^2 in Germany, indicating that there is potential for significantly more deployment. In reality, the limit on onshore wind deployment may be driven more by public acceptability rather than the availability of suitable land per se.

Planning process

Wind farms that are less than 50MW in size are generally handled by the Local Planning Authority of the proposed site. Larger projects require consent under Section 36 of the Electricity Act 1989. For Scotland this is handled by the S36 Consent Team, in England and Wales by the National Infrastructure Directorate at the Planning Inspectorate and in Northern Ireland by the Department of Enterprise, Trade and Investment. Wind farm applications that are rejected by the LPA can be submitted at appeal to the Secretary of State, and are normally handled by a planning inspector. This is a lengthy process, incurring significant costs for both developer and the LPA. If the wind farm wins at appeal, the LPA will pay for all legal costs.

For projects that are greater than 50MW in capacity, and thus subject to a ministerial decision, time spent in the planning system is highly variable between projects and

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34 The NREAP (2010) suggests 15GW by 2020, whilst the Renewable Energy Roadmap (DECC (2011a)) implies 10-13GW, assuming a 28% load factor.

35 DECC (2011a)

between years. Over the last three years, ministerial level projects have had an average time in planning (from date submitted until consent) of around four years[36]. For projects determined by the LPA, the average time to reach consent from submission is around one year if the project does not go to appeal. However if the project does go to appeal the process can be stretched to two or more three years.

The government has set out planning system reforms as a priority action that is designed to accelerate the planning process. Recent developments in this area include:

- The National Planning Policy Framework (NPPF), published in March 2012. This framework seeks to improve the planning system that determines wind farms in England by consolidating existing planning policies into a single document and introduces a presumption in favour of sustainable development. It includes a suggestion that Local Planning Authorities (LPAs) should identify suitable areas for renewable generation.
- The 2011 Localism Act removes Regional Spatial Strategies, which included regional targets for renewable energy, and replace these with more emphasis on local community consultation. The act also transferred authority to the Secretary of State for Energy on nationally significant infrastructure projects in England and Wales.
- Responsibility for granting Section 36 consents has been transferred from the Infrastructure Planning Commission (IPC) to the National Infrastructure Directorate (part of the Planning Inspectorate).

Historically, approval rates for projects below 50MW have been around 60-70%, while for projects above 50MW the recent approval rate has been in the range 80-90%[37]. This might be a consequence of the types of projects that apply at the ministerial level – such projects are more likely to be in remoter areas than smaller projects and hence might give rise to fewer objections. Additionally, decisions at the ministerial level may add additional weight to the fact that projects will be contributing at the national level.

Supply chain and availability of finance

The supply chain in the UK for onshore wind is well developed and forms part of what is now a large global industry. The majority of turbines are imported, but production of domestic tower and turbine components is increasing. Supply of turbines and associated infrastructure is a mature business with supply and demand well balanced through long term contracts with foreign turbine manufacturers. Onshore wind is a growth technology in many areas of the globe but this is not expected to significantly affect availability of turbines for the UK. (Indeed there is currently surplus manufacturing capacity in the global onshore turbine market.) Hence we do not see supply chain availability as likely to impose a constraint on deployment in the future.

Compared to offshore wind, availability of finance is less of an issue for onshore wind. Even under the current ROC regime there is a wide range of investors interested in onshore wind, including private equity, infrastructure funds, many banks, and some pension funds. It is anticipated that introducing CfDs in place of ROCs could attract additional investors by substantially removing electricity market risk. Whilst there are fewer investors interested in investing at the development or construction stage, it is now

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[36] RUK (2012)

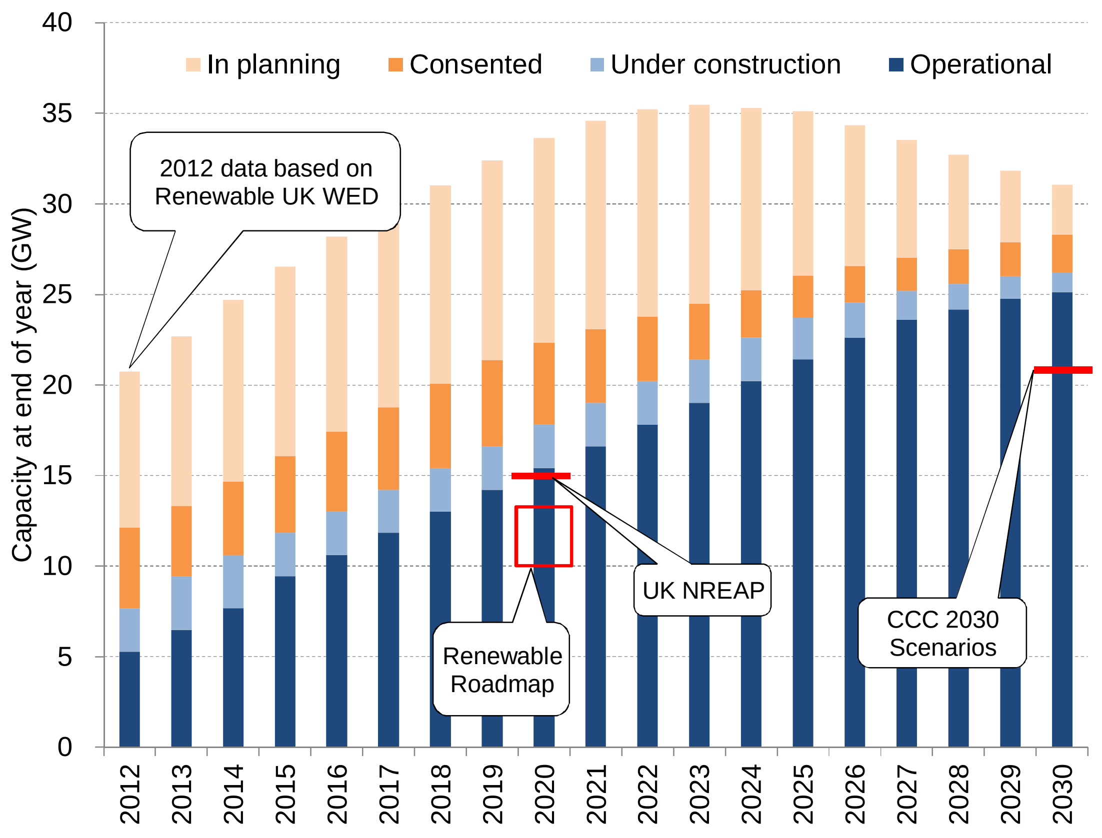
[37] RUK (2012)

common practice for developers to refinance a project once it is operational (for example by selling down equity) in order to raise capital to fund the next project.

2.3.3 Deployment timeline to 2030

We have developed a feasible timeline for onshore wind based on the current pipeline of projects and considering the evolution of future deployment in the light of the issues described in Section 2.3.2 – see Figure 10. Each column shows the projected capacity at each stage of development at the end of the calendar year. The 2012 column shows our existing view of the existing pipeline, based on Renewable UK's Wind Energy Database in January 2013.

Figure 10 – Onshore wind deployment timeline



The UK NREAP value refers to the National Renewable Energy Action Plan for the UK published in 2010 – for onshore wind this projected 14.9GW of total installed capacity by 2020. The Renewable Energy Roadmap published in 2011 and updated in 2012 implies between 10GW and 13GW by 2020[38]. The Committee has previously developed scenarios based on an assumption that 21GW of onshore wind might be achievable by 2030[39]. In order to achieve 13GW by 2020 and be on track for 21GW by 2030, onshore wind deployment will require around 12% growth per year from 2012 to 2020 and around

38 DECC (2011a) and DECC (2012)

39 Pöyry (2011) –High scenario.

5% per year from 2020 to 2030. This compares to a growth rate between 2011 and 2012 of around 18%[40] , suggesting that such a growth rate is plausible when considered in the context of historic growth.

We have constructed the timeline by considering the amounts of capacity flowing through the various stages of development or being rejected. We differentiate projects above and below 50MW, and also between England, Scotland, Wales, and Northern Ireland, as the time spent in development and also the likelihood of being awarded planning permission varies significantly between these groups.

- We assume that the number of new applications reduces annually by 150MW (2012-2020) and 300MW (2021-2030) as viable sites reduce, from a starting point of 2.7GW of new applications in 2012[41]. As discussed in Section 2.3.2, it is not clear what the overall limit to availability of sites might be.

- We assume that the total capacity of the planning system to determine planning applications remains constant at around 2GW per year. This might be considered conservative if there is clear Government commitment to onshore wind, since presumably planning capacity is ultimately within Government control or influence – particularly for projects above 50MW. The rate of determination of planning applications constrains our timeline, and as a result the current large backlog (around 7GW) of projects in the planning system remains until new applications significantly fall

- Of those projects that are determined, we assume a long term reduction in approval rates, both at local and ministerial level, as the 'best' sites continue to be used up and new applications trend toward sites with more planning issues. Starting from current approval rates for each region and size category (based on an average of the last few years[42]), we assume a decline of one percentage point per year to 2020 and four percentage points per year thereafter (see Table 4). Clearly this is somewhat arbitrary, as it is very difficult to predict how approval rates might change as more and more wind farms are built.

- Once a project is consented, we then assume it takes a further two years on average to satisfy any planning conditions and to arrange finance. We then assume a two year construction period.

- We assume an operating life of 24 years. At the end of this time we assume some projects repower with larger turbines and hence increase capacity, while the remainder repower with similar sized turbines, for example owing to planning restrictions. Repowering becomes significant only in the late 2020s as most of the existing fleet has been installed since the commencement of the renewables Obligation in 2002. For example we assume around 800MW of repowered capacity is commissioned by the end of 2030.

As a result of the above assumptions, operational capacity grows at around 1.2GW per year to around 2026. This is the consequence of a continued healthy supply of new projects coming forward, and a steady rate of planning determinations with only a minor

40 Comparing RUK (2011) and RUK (2012)

41 RUK (2012)

42 CCC (2012)

decrease in approval rates. From around 2027, the amount of capacity installed per year falls significantly, primarily owing to falling approval rates.

Table 4 – Planning approval rate assumptions

Size	Region	Approval rate 2013	2020	2030
<50MW	England	58%	51%	11%
	Scotland	72%	65%	25%
	Wales	90%	83%	43%
	Northern Ireland	60%	53%	13%
>50MW	England	77%	70%	30%
	Scotland	76%	69%	29%
	Wales	76%	69%	29%
	Northern Ireland	84%	77%	37%

The timeline exceeds the 2011 Renewable Energy Roadmap's vision for 2020 deployment. As can be seen in 2012, there is enough capacity that has already been consented to nearly meet the higher level Renewable Energy Roadmap prediction of 13GW (although not all consented projects may proceed). By 2030, our assumptions indicate that 25GW of onshore wind could be achieved, higher than our previous assessment for the Committee of 21GW[43]. Since the previous assessment, new projects have continued to enter the planning system, including some very large projects in Scotland, and planning approval rates have been sustained[44].

However, this deployment projection is conditional on the assumptions listed above – in particular on continued government support for onshore wind and on no significant increase in planning rejections (over and above the assumptions listed above). Note also that we assume any grid access constraints are short term only and are resolved in the long term through appropriate network regulation. There may also be potential to develop more than 25GW if new sites continue to enter the planning system, if the capacity of the planning system can be expanded, or if approval rates do not decline as fast as we assume. Hence there might be an opportunity to use onshore wind to fill any shortfall in the deployment of other low-carbon technologies.

Clearly there is a high level of uncertainty associated with our timeline, which is dependent on high level assumptions about available sites and the level of future planning approvals. The scope of this study does not allow for a detailed assessment of the former, and the latter will depend on various non-quantifiable various factors such as the level of political will and public perceptions in relation to onshore wind.

43 Pöyry (2011)

44 RUK (2012)

2.4 Nuclear

2.4.1 Overview of the nuclear pipeline

Over the next 20 years the majority of the almost 11GW of existing nuclear capacity in the UK is likely to permanently close as it reaches the end of its viable lifetime. Thus new nuclear build is required to maintain the present generation contribution from nuclear of around 20% of overall electricity supply. Nuclear is a zero carbon fuel source for electricity generation and so the possibility of an expanded nuclear generation capacity offers one means of contributing towards decarbonising the electricity sector.

Government energy policy sees nuclear power as having a key role to play in delivering a low-carbon generating capacity alongside other low-carbon options. However it is for the private sector to initiate, fund, construct and operate new nuclear plants, and the role of Government will be limited to addressing potential barriers in delivering the necessary private investment in new nuclear capacity, and to providing revenue support through CfD FiTs.

DECC's aim is to have the first new nuclear power stations operational and generating electricity by around 2019[45]. In support of this aim, DECC has facilitated various supporting actions to address potential barriers to private sector investment in nuclear new build, aimed at removing uncertainty regarding factors that have delayed previous nuclear power plant construction in the UK and abroad. These actions include:

- approving sites for potential new nuclear powers stations through National Policy Statements (NPS);
- assessing reactor designs to establish whether the benefits (social, economic or other) outweigh the health risks (from ionising radiation) through a process called Regulatory Justification;
- agreeing standard design aspects (safety, security and environmental) for UK deployment of each new reactor type through the Generic Design Assessment (GDA) process in order to reduce risks associated with the regulatory licensing process (by giving developers assurance that the engineering design proposed will not require substantive late modifications, with knock-on effects to the construction programme and cost); and
- establishing fixed arrangements to make sure operators of new nuclear power stations put aside sufficient funds to pay for future waste disposal and decommissioning.

As a result, there are currently eight sites in the UK approved for new nuclear plants with a combined capacity potential of around 23GW, and three different development consortia are at various stages of development projects on a number of these sites. At the time of writing, DECC is in negotiations with EDF over an appropriate CfD strike price for the first new nuclear plant in the UK which has been proposed for the Hinkley Point site. If these are successfully concluded then this project could reach FID in 2013. .

45 https://www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies

2.4.2 Factors affecting deployment timescales

The rate of deployment of nuclear will depend on a number of factors, which could act as constraints limiting the rate at which new projects are developed.

Reactor designs

In order to reduce uncertainties in the licensing and approval of new nuclear reactors, a programme of pre-licensing assessment known as the Generic Design Assessment (GDA) is undertaken by the Office for Nuclear Regulation (ONR) and the Environment Agency (EA) and examines reactor designs promoted by vendors and potential developers. The GDA is arranged in four stages of increasing detail and was originally envisaged to take around 40 months to complete.

Table 5 provides the latest status on the licensing and approval of the different nuclear reactors which might be deployed in the UK. The only reactor type to have completed the full GDA process is the European Pressurised Water Reactor (EPR) offered by Areva. Hitachi's Advanced Boiling Water Reactor (ABWR) has recently been submitted into the GDA process, while the GDA for Westinghouse's AP 1000 reactor is currently on hold.

Nuclear deployment in the UK will benefit from successful completion of the GDA process for another reactor type in addition to the EPR, in order to introduce more competition for new nuclear generation. However the GDA process for the ABWR is unlikely to be completed before 2017.

Availability of sites

The National Policy Statement for Nuclear identifies eight sites that are deemed suitable for new nuclear development in the period to 2025[46]. These sites are, not surprisingly, sites of operating (or recently closed) nuclear power stations. It is understood that these sites were selected on the basis of proximity to grid, local support to nuclear technology, access to appropriate infrastructure (cooling water, marine off-load), and absence of difficult site features. The level of capacity which will be deployed at each site is uncertain, depending on factors such as choice of reactor and site size. Table 6 summarises the potential capacity development at each of the sites, as evidenced by grid connection agreements obtained from National Grid[47] and our own assumptions based on likely reactor selection.

[46] DECC (2011b)

[47] NGC (2013)

Table 5 – Reactor types

Vendor	Reactor Type	GDA Progress	Comments
Areva	European pressurised water reactor (EPWR)	Stage 4	Design Acceptance Confirmation from ONR and EA provided (December 2012)
Westinghouse	AP1000 (PWR)	Stage 3	Westinghouse have paused their progress through GDA process
Hitachi	Boiling water reactor (ABWR)	Stage 1	ONR and EA signed agreements to begin GDA process (April 2013)

Source: Office for Nuclear Regulation and Pöyry analysis

Table 6 – Approved sites for nuclear development

Developer	Station Name	Connection capacity (MW)	Assumed reactor type	Assumed generation capacity (MW)
EDF	Hinkley Point C1	1,670	EPR	1,600
EDF	Hinkley Point C2	1,670	EPR	1,600
EDF	Sizewell C1	1,670	EPR	1,600
EDF	Sizewell C2	1,670	EPR	1,600
Horizon	Wylfa C1	1,200	ABWR	1,300
Horizon	Wylfa C2	1,200	ABWR	1,300
Horizon	Wylfa C3	1,200	ABWR	1,300
Horizon	Oldbury C1	1,600	ABWR	1,300
Horizon	Oldbury C2	1,600	ABWR	1,300
NuGen	Moorside 1	1,600	EPR	1,600
NuGen	Moorside 2	1,600	EPR	1,600
EDF	Dungeness C	1,650	EPR	1,600
EDF	Bradwell B	1,670	EPR	1,600
EDF	Heysham	na	EPR	1,600
EDF	Hartlepool	na	EPR	1,600
				22,500

Source: NPS-1, National Grid, Pöyry analysis

Supply chain capability

The nuclear supply chain in the UK requires development in order to support a new nuclear build program. It is around 20 years since the last nuclear reactor (Sizewell B) was built in the UK and therefore the UK supply chain capability starts from a very low base. Despite this challenge, the Office for Nuclear Development (and the industry itself) is confident that the nuclear supply chain can be developed to meet the needs of the industry without significantly affecting deployment timelines.

The construction of a nuclear power station moves through several phases and as a result depends on different skill sets at different stages. The first three years of construction are dominated by civil works, followed by around one year of mechanical and one year of

electrical installations. Overlapping nuclear construction projects within a single site or across multiple sites will ensure that resource potential is maximised. We estimate that the optimum time gap between project FID dates will be around 18-24 months from a supply chain perspective.

In our view, the equipment supply chain is less of an issue than the supply chain for on-site construction owing to the existence of a large international industry and a slow-down in nuclear development in other countries as a result of the Fukishima accident. Certain of the larger components will be manufactured abroad as the UK does not have the manufacturing capability for these, although smaller components may still be sourced in the UK. Hence many components will be constructed abroad, leaving just the final assembly defining the requirement for on-site resource. This highlights the international nature of the nuclear supply chain. Each of the three proposed nuclear reactor types has been deployed elsewhere in the world and each vendor can leverage their international supply chain development (as well as potential UK) for any UK project.

International experience

The ability to learn from international experience will be important. Two nuclear projects at Olkiluoto (Finland) and Flammanville (France) are nearing completion in Europe. Both plants are based on the EPR reactor and have encountered issues through construction that have delayed the operation start date and led to cost over-runs. There are many lessons learnt that can be taken from these first two deployments of the EPR technology such that the same issues can be avoided in the UK. For example, the UK's GDA process should ensure that many issues are resolved prior to FID and the commitment of the vast majority of capital expenditure.

The Far East build programme continues in South Korea, and China has plans for nuclear power expansion. China has 17 operational nuclear reactors and despite a pause in development for a full safety review post Fukushima, the country has 28 new reactors under construction (mostly powered by PWRs). Whilst new nuclear development has stopped in Japan, there is plenty of recent experience in the deployment of Hitachi's ABWR plants – including 4 year build times. If Horizon (which is owned by Hitachi) goes ahead with its UK projects at Wylfa and Oldbury, these projects should benefit from Hitachi's previous experience of ABWR construction. However it is unlikely that similar build times can be achieved at first as it will take some additional time to adjust to a regulatory environment in the UK (and build UK supply chain knowledge).

Government support

The Government is currently in the final stages of negotiation with EDF to set an appropriate CfD strike price for a new nuclear plant at Hinkley Point. The objective is to establish a fair price that will permit EDF to invest in new capacity without overpaying and burdening consumers with excessive costs. The Government is keen for nuclear to play its role in delivering a low-carbon future and hence a successful outcome of these negotiations is important for maintaining the confidence of developers (and investors) in the UK.

Availability of developers

There is a limited number of parties who are likely to have the expertise and appetite to develop new nuclear projects in the UK – these are likely to be certain large utilities and nuclear manufacturers. Even for these parties, the sheer scale of a nuclear project means that it can represent a significant risk for a company, and it is likely that consortia will form to share this risk. At present there are three developers progressing UK projects and

there may be a limit to the number of sites each is willing to develop at one time, in order to manage the risks involved.

Availability of finance

A related issue is the availability of finance, particularly during the development and construction phases. Nuclear projects are very capital intensive and take a long time to build. Revenues do not begin to accrue until a plant is operational and this may be ten years or more after initiating development owing to extended project pre-development and construction times.

Development funding (before FID) is typically provided from a developer's own balance sheet, but this can amount to several hundred million pounds for a single project. At FID there is the possibility of bringing in bank finance, but it is as yet uncertain what the appetite of banks will be for nuclear projects. Other sources of funding could potentially be private pension funds, insurance funds or sovereign wealth funds. Many multilateral financial institutions, which could potentially be a good source for nuclear project funding, have policies prohibiting such investments. This trend has increased post Fukushima.

In the current economic climate there are considerable challenges in obtaining private sector for new nuclear projects. These projects are very capital intensive compared to competing generation capacity technologies such as those powered by coal and gas. With concern across the EU with respect to reducing carbon emissions, many governments offer renewables projects favourable levels of subsidy by comparison to nuclear. The cost and risk of nuclear projects do not appear stable to investors, with a perceived high potential of escalating costs and construction delays and with additional safety features post Fukushima adding to the cost profile. Finally investment bodies are concerned that backing nuclear projects could have a negative impact on their perceived risk exposure from credit rating agencies. All of these reasons mean that new nuclear faces few financing options and explains why many international projects are supported by governments (China, South Korea, and UAE). Government funding has been ruled out in the UK and therefore new nuclear projects may at first rely on the ability of utilities or developer consortia to fund projects off the strength of their balance sheet until the perceived risk is lowered to a level that attracts large institutional investors.

Once a project is operational it is likely that further finance can be raised from lower risk investors. However the ability to finance development and construction could limit both the number of developers who enter the UK market and the number of projects each developer can develop at the same time.

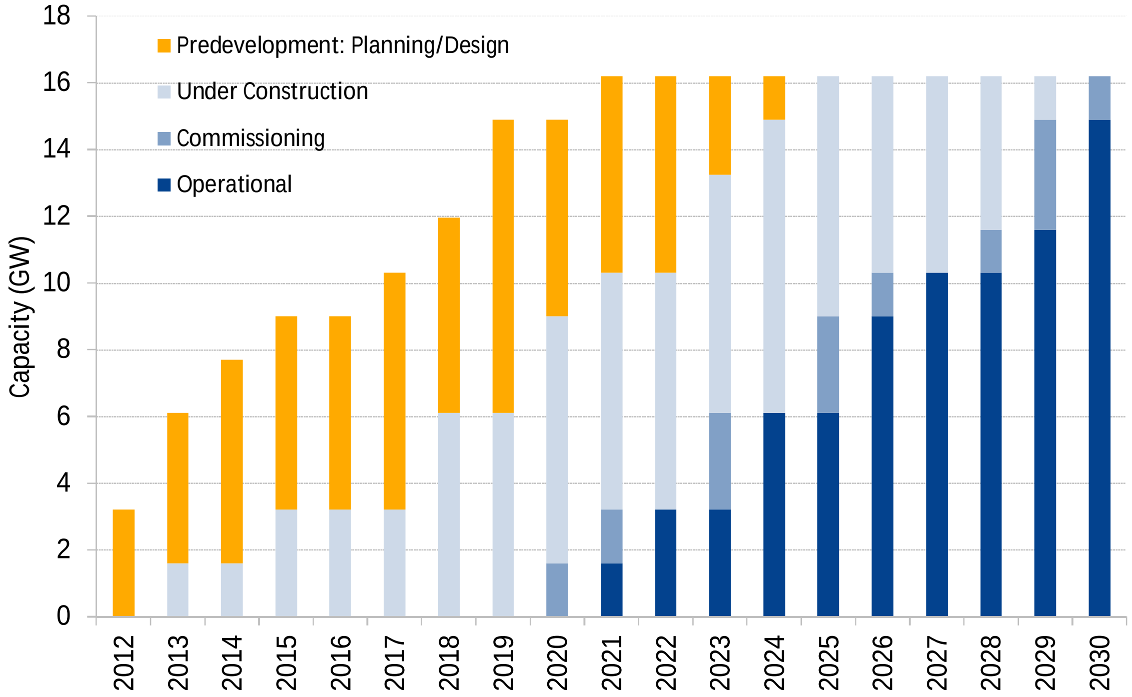
Long term waste disposal solution

The Government continues to look for a site to host the proposed geological disposal facility for higher activity nuclear wastes. This follows the decision by Cumbria County Council not to support a facility in West Cumbria. If a long term solution is not found then there may be public resistance to a large scale new nuclear programme.

2.4.3 Deployment timeline to 2030

Based upon our understanding of the nuclear industry sector in the UK and cognisant of a number of other studies and reports on the subject we have developed a timeline for the introduction of new nuclear capacity. The deployment timeline shown below in Figure 11 is our view of the maximum feasible rollout to 2030. This deployment timeline delivers 16GW of new nuclear capacity by 2030, if suitable financing for construction can be made available.

Figure 11 – Nuclear deployment timeline



The timeline takes account of the different stages required to deliver a new nuclear reactor including the time required for predevelopment, construction and commissioning. Our assumed build times are five to six years, based on recent work by Parsons Brinckerhoff for DECC[48]. Predevelopment includes all site preparations, planning and design processes required prior to pouring first nuclear concrete on site. The final investment decision (FID) must be taken by the developer before transitioning into the construction phase. Nuclear construction is the crucial phase that determines the success of a project as overruns can be hugely costly. The nuclear reactor begins generating electricity from the start of the commissioning period but the reactor is considered to be in a ramping up phase for a period of 1 year as various tests are completed before becoming fully operational.

Figure 11 shows the first nuclear construction beginning in 2013-2015 at Hinkley Point. In 2018 we see another 2.9GW of capacity entering construction, some of which we assume will be for the second nuclear reactor type, Hitachi's ABWR. By 2020 a staged rollout of nuclear capacity begins, optimising the capability of the nuclear construction supply chain. We see total deployment limited to around 16GW capacity limit by 2030, primarily owing to a limited number of developers in the UK market. (We discuss below what is required if the UK is to go beyond 16GW by 2030.)

Achievement of the timeline in Figure 11 is dependent on a number of assumptions or conditions as follows:

- Underpinning this roll-out is the assumption of a positive policy environment to enable a new nuclear build program in the UK. Whilst nuclear capacity development will be

[48] PB (2012). We assume the central estimates for pre-development and construction time.

financed and constructed by the private sector, the UK industry is dependent on supportive national policies and public opinion to make the UK market attractive compared to investment opportunities elsewhere.

- We assume three developers are active in developing UK projects. Currently EDF, Horizon and NuGen have publicly declared their desire to develop new nuclear capacity in the UK.
- So far only one nuclear reactor type has completed the GDA process, Areva's EPR design. We assume that a second reactor type, Hitachi's ABWR completes its GDA process by 2017/2018 enabling roll-out diversity. This step is presumed necessary to bring Horizon into the UK market.
- We have assumed an 18-24 month time lag between projects per developer in order to maximise the supply chain capability.
- Financing large infrastructure projects with long term investment funds in the current financial environment is challenging due to the perceived risk associated with volatile markets. Achieving a stable investment environment for new nuclear underpinned by the government strike price is important to enable these projects to win financing.

Key to the achievement of the deployment profile indicated in Figure 11 will be the success of early projects in terms of build time, cost, and early plant performance – as this will provide confidence for investors in subsequent projects.

The rate of new build will also be determined by the capital invested already by the developer utilities and the ability to raise further capital against operational assets (as funded the EDF nuclear programme in France in the 1970's). The market expectation will be for plants to be constructed more quickly and for lower cost, drawing on experience as the supply chain matures. (The cost of constructing new nuclear capacity is explored in greater detail in Section 3.4.)

Our timeline is based on the development by 2030 of five of the eight sites approved in the National Policy Statement for Nuclear. To date there have been no public planning announcements concerning the remaining three sites, but these could in theory increase the national capacity potential to 21-25GW depending on whether the sites can accommodate single or double reactors. We assume that, without the entry of additional developers, this potential extra capacity will not be deployed by 2030 due to financing constraints of the three developers in the market. However it is possible that additional developers might enter the market in the future, for example once the CfD regime has become established. Because of the lead times involved, a developer would need to begin development of one of these additional sites by around the end of this decade if it is to be operational by 2030. Alternatively, an existing developer may be able to sell part of its interest in a project once it is built in order to recycle capital for another project (as is common in the offshore wind sector), but this is unlikely to happen before the early 2020s.

Additional sites will be required to develop nuclear generating capacity even further beyond 21-25GW. In our view, for new sites to be operational by 2030, DECC would need to begin a programme of identifying and approving new sites around the middle of this decade to allow for a predevelopment and construction period of around ten years. However we assume a low appetite to initiate this process from industry players or government so long as there are approved sites showing no signs of development planning.

2.5 CCS

2.5.1 Overview of project pipeline

In March 2013 DECC announced two preferred bidders for the UK's £1bn Carbon Capture and Storage Commercialisation Programme Competition, out of the four full chain projects (capture, transport and storage) that were shortlisted. The two preferred bidders are:

- the White Rose Project at Drax, a 304MW oxy-coal plant; and
- the Peterhead Project in Scotland, a 340MW CCGT post combustion plant.

The Government expects to agree terms with the two preferred bidders by the summer of 2013 for the Front End Engineering Design (FEED) studies. These will take approximately 18 months to complete and so the expectation is that the first CCS projects in the UK will reach a final investment decision (FID) in early 2015.

The European Commission announced in April 2013 a second call for proposals for its New Entrant Reserve (NER) funding for CCS projects. The Government has stated that it intends to support only projects which, on the date submissions are due from Member States (3 July 2013), remain in the UK CCS competition. This means that the two reserve projects from the UK competition still have the possibility of securing EU funding in support of their projects. The two reserve projects are:

- the Grangemouth Project in Scotland, a 570MW IGCC plant; and
- the Teesside Low-carbon Project, a 330MW IGCC plant.

Whilst the recent announcement of the two preferred bidders in the UK competition represents a big step forward for CCS in the UK, the CCS deployment landscape remains largely unchanged since we completed a study for the Committee in 2009 on the potential deployment of CCS to 2030[49]. We are now a few years further on without any material developments to the situation as it was then. Our previous study indicated that a commercial rollout of CCS could begin no sooner than 2024 with an annual build rate of 1GW/yr for the first three years ramping up to 2GW/yr thereafter. It is clear that delays over the past few years have had a serious impact on the potential CCS capacity by 2030, with the later 2020s crucial for the building up of CCS capacity.

2.5.2 Factors affecting deployment timescales

The rate of deployment of CCS will depend on a number of factors. These factors could act as constraints limiting the rate at which new projects are developed.

Pre-commercial development phases

Our 2009 report discussed a CCS rollout in terms of three key phases. The first two stages comprise 'pre-commercial' projects. These projects require Government support to secure investment and are deemed necessary due to the unproven nature of the various carbon capture technologies at this scale and the challenge of integrating these new plants with a transport and storage infrastructure. The technology involved in transport and storage is more established, based on existing experience in the oil and gas sector. For example, there is experience of the use of carbon dioxide for enhanced oil recovery (EOR) in the USA.

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49 Pöyry (2009)

In our view, each phase of CCS roll-out (two pre-commercial phases and then commercial projects) will need to be staggered by around three years to enable learning experiences to be absorbed by the industry at each stage. These learning requirement are a major factor which limits the deployment potential to 2030. Our previous study assumed that investment decisions on one phase would not be taken before accumulation of three years' operating experience of the preceding phase, to enable developers to take account of production learning. In this study we have made the more aggressive assumption that the three year gap is applied from the FID date for the preceding phase. This decision results in greater overlap between phases, with projects in new phases only able to benefit from mid project construction learning prior to making an FID. We have taken this approach in this study to represent a continual momentum in the CCS industry underpinned by sustained government support and a positive policy environment for CCS.

Supply chain capability

The limiting constraint in supply chain development is the earliest date by which a commercial plant could become operational. Here we assume that is 2025/26 (based on FID 2021). The evidence base agrees that in the early years of deployment 1GW/yr is a reasonable limit to expect although this can ramp up 2GW/year after several successful years of deployment and the right signals to industry[50].

Transport and storage infrastructure

The UK competition entrants are all end-to-end projects, meaning that they include development of transportation and storage components as well as the capture plant itself. Hence the T&S infrastructure for these projects may not be developed as part of a larger co-ordinated infrastructure plan, and instead could be based on CO_2 transport and storage ("T&S") infrastructure sized for that specific project. Whilst avoiding building redundant capacity into the T&S network will ensure the lowest capital costs for early projects, this latter approach may not help reduce costs and could hinder deployment rates in the long term. The UK CCS Cost Reduction Task Force reports that building a large integrated network of transport pipes and interconnected storage hubs will be important for bringing down the cost of CCS and enabling it to compete with the other low-carbon options[51]. At present the strategy for the provision of this infrastructure in the longer term remains unclear – for example whether it will be supported through revenue support to CCS generation projects or through some alternative means.

In the meantime, early projects will face a difficult challenge of balancing the need to demonstrate low individual project costs with the need to scale up to enable economies to bring down the costs of future projects, and clearly there is a role for Government here. Analysis of the interplay between investment in capture plant capacity and T&S infrastructure is beyond the scope of this project and we assume in our deployment timeline of CCS capacity that the necessary policies are in place to ensure the provision of an appropriate T&S infrastructure for all projects.

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50 Pöyry (2009). The CCSA also suggests that 1GW/yr occurs in early years of deployment then 2GW/yr in later years (CCSA (2011)), although they see this as starting from 2018 rather than 2025.

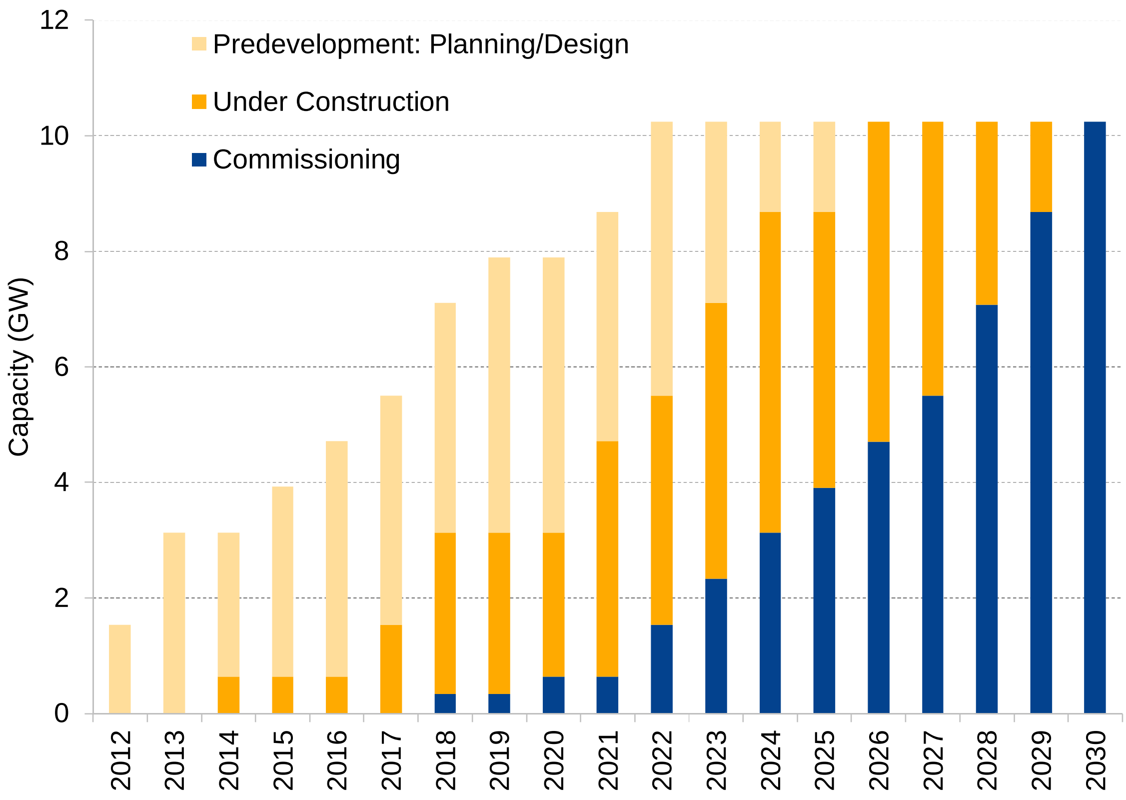
51 CCS CRTF (2012)

2.5.3 Deployment timeline to 2030

A major uncertainty in relation to CCS deployment is which of the various capture technologies[52] will be preferred in the longer term. In developing a timeline for CCS deployment, we assume that a variety of different capture technologies is progressed[53]. We have assumed that a mixture of gas and coal capture plant technologies are supported through the pre-commercial phases, but in the commercial rollout we have predominately chosen post-combustion gas capture plants. This is because this capture technology appears to have the lowest cost estimates in the evidence base. Whilst we recognise that there is uncertainty attached to the cost estimates for CCS (see Section 3.5), this has enabled us to demonstrate the trajectory for development of a particular capture technology. In reality the CCS pipeline may make a different technology choice.

Our projected timeline (Figure 12) delivers a total of just over 10GW of CCS capacity by 2030 – around 3GW of coal CCS and the remainder gas CCS.

Figure 12 – CCS deployment timeline



In this study we have shifted the timelines reported in our previous study backwards in time (i.e. later) with the following results:

52 The capture technologies we have considered are pre- and post-combustion gas CCS, coal post-combustion capture, coal IGCC, and coal oxy-fuel.

53 It is outside the scope of this project to undertake a detailed assessment of which will come forward in reality.

- the first two pre-commercial phase projects reach FID in 2014/15 (640MW);
- the second round of three pre-commercial phase projects reach FID in 2017/18 (2500MW); and
- commercial phase projects begin reaching FID from 2021.

To enable a smoother transition from pre-commercial to commercial deployment of CCS, we have assumed that 'full-sized' capture plants are supported in the second phase of pre-commercial projects to demonstrate the full capability to potential investors and developers. In addition, shared learning across the industry (both domestic and international) will be important for the successful transition from pre-commercial projects to commercial deployment

Owing to the shortening of the time delay between the pre-commercial phases and commercial rollout (compared to our previous study), we have assumed a lower annual build rate and more modest increases in supply chain capacity. We have assumed annual additions to capacity of 0.8GW/yr between 2022-2027 increasing to 1.6GW/yr by 2028, compared to the limits of production cited in the evidence base (1GW/yr rising to 2GW/yr).

Clearly there is a high level of uncertainty associated with our timeline, which is dependent on high level assumptions about when projects proceed and which technologies they select. However it is clear that achievement of 10GW by 2030 is dependent on sustained Government commitment to a large scale CCS programme. Key to this will be the introduction of clear policies to develop the required T&S infrastructure. A clear policy signal that Government is committed to CCS should also increase investors' confidence, leading to a reduced cost of capital, and hence overall cost, of CCS projects.

In its recent Communication on CCS, the European Commission invited views on whether additional policies are needed to support CCS roll-out, including for example a CCS certificate system (i.e. obligation). As the UK has a relatively large number of proposed CCS projects, it might be well placed to take advantage of any wider European policy supporting CCS.

Achievement of deployment levels greater than 10GW by 2030 would require construction of additional commercial plants during the commercial roll-out period in the late 2020s. For example commissioning one additional 800MW plant per year between 2025 and 2030 would increase deployment to 15GW in 2030. This would require total deployment rates of 1.6GW/yr for 2025-2027 rising to 2.4GW/yr in 2028-2030. This might be seen as just plausible, given that the 'dash for gas' delivered 2.8GW per annum of CCGT capacity at its peak, and compares with the 16.5GW we identified for our high deployment path in our previous study for the Committee[54]. However, such increase deployment stretches credibility, as we would then need to assume that a large number of commercial projects reach final investment decision before the second pre-commercial phase projects (i.e. commercial scale demonstration projects) have completed construction.

54 Pöyry (2009)

2.6 Biomass conversion

2.6.1 Overview of existing pipeline

In its Bioenergy Strategy[55], DECC has signalled that it sees biomass conversion as an effective means of contributing to meeting the UK's 2020 renewables targets. This followed a similar conclusion in the Committee's own review of bioenergy[56]. For the Government, biomass conversion has the advantages that it requires lower support than new build biomass stations and can potentially deliver very large volumes of renewable electricity since coal units are typically several hundreds of MW in size and can run at high load factors.

Sustainable biomass[57] is generally perceived as a limited resource, and the studies mentioned above consider whether electricity generation represents the best use of this resource. The Committee argues that if we are to meet the long term (2050) carbon targets, then biomass use should be targeted to applications for which there are fewer low-carbon alternatives available, such as aircraft fuel or high-temperature process heat. Hence an additional attraction of biomass conversions is that are likely to have a relatively short life (compared to new build biomass) owing to the advanced age of the existing coal fleet. This means that they do not lock in biomass in the longer term, and the biomass fuel supply chain built up to serve them is potentially available for these other applications in the longer term.

For coal station operators, biomass conversion[58] offers a number of attractions. The new ROC support levels announced in the recent Renewables Obligation Banding Review mean that biomass conversion has the potential to be economic, even allowing for the higher cost of biomass compared to coal[59]. Also biomass generation does not face the carbon costs borne by coal generation (through the EU Emissions Trading Scheme and the Government's new Carbon Price Support levy). Converted stations are also likely to run at higher load factors than coal stations as the ROC support means that their effective short run marginal cost is lower.

None of the existing coal fleet is compliant with the new emissions limits set out in the Industrial Emissions Directive[60] (IED) and effective from 2016. All face imminent decisions about how they comply with IED – for example whether they should invest in additional abatement equipment or choose the 'limited life duration' opt-out which allows them to run for 17,500 hours before closing. Biomass conversion offers an additional compliance option since the additional financial support (through ROCs or CfD FiTs) could help to justify the investment required to fit any necessary abatement equipment and otherwise extend the plant's lifetime.

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55 DECC (2012b)

56 CCC (2011)

57 In this report, whenever we refer to biomass, we mean 'sustainable biomass', meaning biomass which meets the sustainable criteria which are applicable at the time.

58 We use the term 'biomass conversion to refer either to conversion to run on 100% biomass or to co-fire biomass with coal at high co-firing percentages.

59 Biomass conversions will also be eligible for CfD FiTs.

60 The IED specifies limits for emissions of sulphur dioxide, nitrogen oxides, and particulate matter. It succeeds the existing Large Combustion Plants Directive with effect from 2016, and IED limits are generally stricter than the equivalent LCPD values.

Because of these attractions, a number of coal station operators have announced plans to convert coal units to biomass or have indeed already done so:

- RWE converted Tilbury in 2012;
- E.On completed its conversion of one unit at Ironbridge in 2013;
- Drax has announced that it will convert three units, beginning with the first in 2013;
- International Power has announced that it is investigating conversion at Rugeley;
- Eggborough Power is planning to convert some or all of its four units to biomass; and
- RWE is considering whether to convert Lynemouth power station to biomass, having recently acquired it from Rio Tinto Alcan.

This list totals around 5GW of capacity, even allowing for the fact that there is typically some down-rating of capacity when a unit is converted from coal to biomass. A number of other coal operators are also thought to be investigating the possibility of biomass conversion.

2.6.2 Factors affecting deployment

Despite this high level of interest in biomass conversion, there are a number of factors which could limit the capacity which actually converts.

Remaining station life

Most of the remaining UK coal fleet was commissioned in the late 1960s or early 1970s, and hence is already forty years old. The newest units are at Drax dating from the mid-1980s so even these are approaching thirty years of operation. Biomass conversion entails a significant capital investment, and operators will only make this investment if they believe the station will be able to run long enough for them to recover this investment.

Tilbury and Ironbridge have both 'opted out' of LCPD and have a constrained number of running hours left before the end of 2015[61]. If they wish to run beyond 2015 they will be required to comply with the 'new plant' emissions standards under IED, which are even stricter than those for existing plant[62].

Government ambition and regulatory uncertainty

The Government has signalled that it supports biomass conversion but only up to a certain limit. For example, the Government has suggested[63] that there will be a separate ring-fenced budget within the Levy Control Framework for biomass conversion (together with solar PV) to prevent these technologies using up the remaining budget if deployment exceeds expectations. In study we assume the total volume of biomass conversion capacity supported by Government does not exceed 4GW. This is based on scenarios developed by the Committee and we believe it represents an upper limit of what may be affordable within the Levy Control Framework (allowing for Government ambition in respect of other technologies).

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61 Plants which opted out of LPCD were allowed to run for 20,000 between 2008 and 2015 inclusive.

62 RWE has announced an intention to extend the life of Tilbury beyond 2015.

63 DECC (2012f)

In addition to this, there are two policy areas of particular relevance to biomass conversions where greater clarity may give investors sufficient confidence to invest:

- The Government has proposed that sustainability criteria for biomass supplied to biomass conversion stations should be 'grandfathered' (i.e. not subject to regulatory change) only until 2020[64].
- The capacity mechanism proposed as part of EMR could have a significant impact on the economics of coal stations (whether they convert to biomass or continue to burn coal). At the time of writing the exact details of the capacity mechanism, and hence the impact on biomass conversion economics, are not yet clear.

Biomass fuel supply

The volumes of biomass required by biomass conversion stations are such that the vast majority of fuel will be sourced from abroad, most likely from regions around the Atlantic basin such as the US Southeast, Canada, Brazil, and Northwest Russia. Pöyry has an established forest industry consultancy practice, and we have advised many UK clients on biomass sourcing for power generation. Our view is that sufficient sustainable biomass is available to meet the demand from 4GW of biomass conversions in the UK, in addition to the expected demand increase from other European countries such as Denmark and the Netherlands. This is based on our assessment of the existing surplus of biomass in the Atlantic basin (which has been increasing in recent years owing to the decline of pulp and paper production in North America) and of the 'biomass paying capability' of other potential sources of demand for biomass (including other European bioenergy producers).

However, this biomass is not available immediately as a supply chain must be established to acquire the biomass from forest owners, pelletise it, and deliver it to the UK. In particular new pellet mills will need to be constructed – these will likely be financed based on long-term off-take contracts from UK utilities. Our view is that it will take up to two years from financial commitment to establish the fuel supply chain, and this is what determines the time to commissioning for biomass conversions. (Conversion of the actual coal units themselves can be achieved within this timeframe[65].)

2.6.3 Deployment timelines to 2030

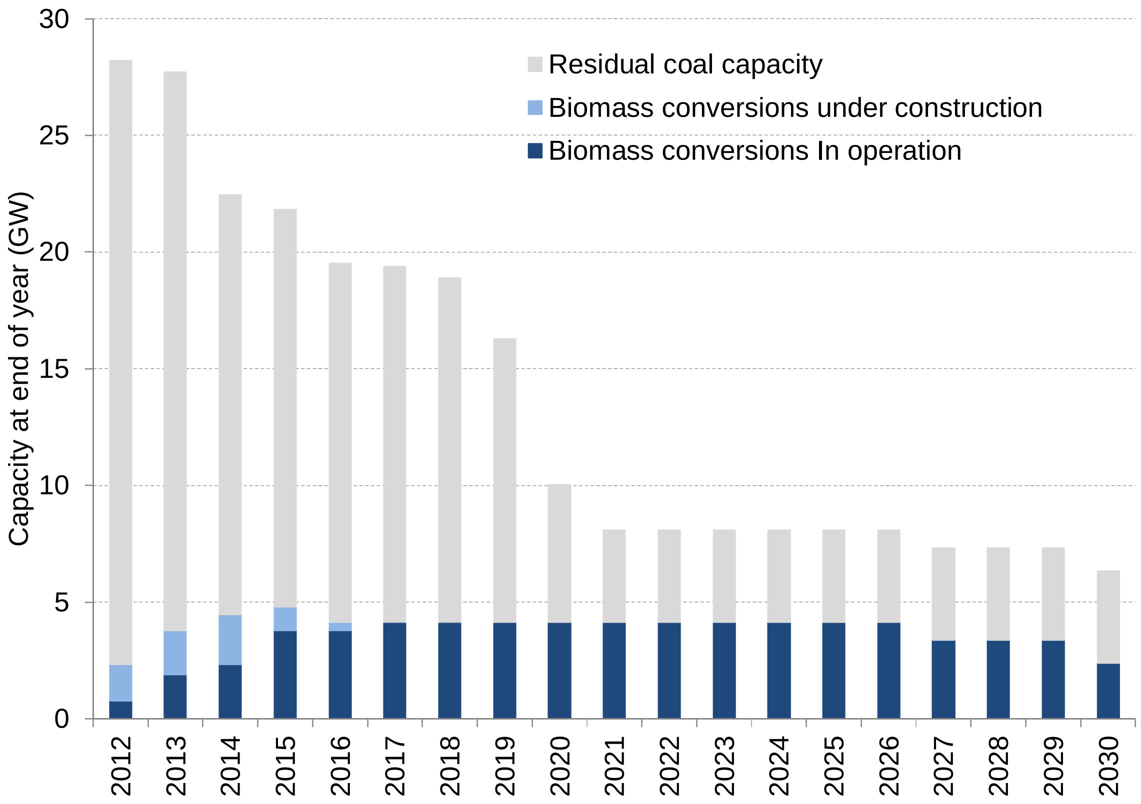
Our deployment outlook for biomass conversion is shown in Figure 13. Conversions come forward relatively quickly as there will be competition to secure the best fuel supplies and government support ahead of other projects.

Whilst we believe that this level of biomass conversion is able to come forward, developers will still be required to address significant challenges in establishing fuel supply chains and infrastructure and in undertaking the conversion works at the plant itself.

64 DECC (2012c)

65 MML (2011a)

Figure 13 – Biomass conversion timeline



Our timeline shows all biomass conversions, whether they opt for support under the Renewables Obligation or for CfD FiTs. For our strike price modelling (in Chapter 4) we assume existing conversions (Tilbury, Ironbridge, and the first Drax unit) opt for ROCs whilst the remainder are supported through CfDs, although we recognise that in practice some of the later units might opt for ROCs also. This affects the potential closure date of a station, since ROC support extends only to 2027 whilst CfD support is likely to extend for 15 years from the date of conversion. In our timeline we assume that a station continues running on biomass beyond the expiry of the support period only if it is economic to do so (comparing biomass price against coal and carbon price[66]). This is the case only for Drax and so the other stations close at this point. (We also assume all stations are physically able to operate to the end of the support period.) Hence there is some uncertainty around when exactly the contribution from biomass conversions to decarbonised electricity will decline, but nevertheless it is unlikely that this contribution will be significant beyond 2030.

2.7 Key messages

In this chapter we have investigated what contribution each of the five low-carbon technologies might be able to make towards decarbonising the grid by 2030. We have constructed projections for deployment timelines which we believe are plausible given

66 Our calculation is based on biomass projections provided by MML (2011a) and coal and carbon prices from DECC's 2012 Updated Energy Projections (DECC 2012d).

sufficient policy commitment from the Government (including successful implementation of CfD FiTs)[67]. Our key messages are as follows:

Offshore wind

- There is a very large potential for offshore wind as witnessed by the 47GW of leases awarded by The Crown Estate. Most of this potential is as yet unrealised.
- The supply chain is still relatively is immature and will need to continue expanding if the sector is to utilise the available wind resource.
- Under reasonable assumptions (for example moderate growth in supply chain to around 1.6GW/yr by 2020 and no adverse changes in planning position), deployment of offshore capacity to around 12GW by 2020 and 25GW by 2030 is feasible.
- A potential restriction on more ambitious growth will be access to finance (which will also have knock-on impacts on sustainable supply chain growth).
- New leasing rounds are likely to be required in the 2020s to reach more ambitious long-term deployment over 40GW because of possibility of attrition in the current pipeline.

Onshore wind

- There is a strong pipeline of potential projects, with around 15GW of capacity at various stages of development in addition to the approximately 5GW already in operation[68]. The overall potential of onshore wind is not well understood.
- Planning is still a major concern for onshore wind developers, particularly for smaller projects that are subject to local planning rules.
- Onshore wind is a mature global industry and supply chain capacity is not considered to be a constraint on deployment in the UK.
- Our deployment projections suggest that around 25GW can be achieved by 2030 based on the assumption that the planning system can continue to process applications at current levels. Streamlining the planning process or increasing planning system capacity could lead to higher deployment.

Nuclear

- Nuclear power will not make any significant contribution until the 2020s.
- We believe 16GW can be achieved by 2030, assuming three active developers in the market. However this assumes a successful GDA process for Horizon's ABWR reactor and no further delays in the development process and no withdrawals by

67 The scope of this study does not include a projection of grid carbon intensity by 2030. However based on our timeline analysis we believe 50gCO2/kWh is still achievable, although the capacity mix to achieve this may be different from that assumed by the Committee in its Fourth Carbon Budget (CCC (2010)) owing to differing rates of progress across the technologies since then.

68 Not all of the pipeline will be developed owing to project attrition, for example because planning consent is refused.

developers.

- A key concern is the availability of developers and of finance during the pre-development and construction phases. This might be the limiting factor on nuclear deployment.

- The three remaining sites identified in the National Planning Statement for Nuclear offer the potential to expand beyond 16GW to around 21-25GW, but it is likely that new developers will need to enter the market to realise this potential.

- A new round of site identification will be required to achieve even higher deployment in the long term. Given the long timescales involved in nuclear development, this process should begin towards the end of this decade to maintain the possibility of continuing the deployment momentum in the 2030s once the current sites are developed.

CCS

- Since we examined CCS deployment for the Committee in 2009[69] there has been little progress in developing the first pre-commercialisation projects. As a result, we believe around 10GW is an upper limit to what might realistically be deployed by 2030, and that CCS will not play a significant role in the generation mix until the late 2020s.

- We retain our view that, in addition to the first two pre-commercial plants supported through the UK CCS Commercialisation Programme, a second phase of full scale pre-commercialisation plants will be required before full commercial roll-out. However achievement of 10GW by 2030 requires that some investors will be willing to commit to commercial projects before these second phase plants are operational.

- It is critical that pre-commercialisation projects are progressed in the next few years to enable the industry to be in a position to deploy commercial phase projects in the late 2020s.

- Our deployment projections assume the early development of an integrated or co-ordinated approach to provision of transport and storage infrastructure in order to access early cost reductions and reduce risk for projects.

- At present there remains much uncertainty around the appropriate capture plant technology options(s) that will be successfully developed (although we do not see this as a major issue).

Biomass conversion

- The existing coal generation fleet offers the potential for biomass conversions to play a role in decarbonisation of the electricity sector to 2030 (but not for the longer term owing to the age of this fleet).

- We project that the amount of capacity which converts may be limited by government ambition to around 4GW. We believe there is sufficient sustainable biomass available

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[69] Pöyry (2009)

to support this capacity.

- Biomass conversions are likely to be implemented relatively quickly as developers compete for fuel supply and for available support.

3. TECHNOLOGY COST DISTRIBUTIONS

This chapter sets out how we construct cost distributions for each low-carbon technology, where costs are expressed as the levelised cost of electricity generation (LCOE) (in £/MWh), taking account of capital and operating costs and assuming the generator will require a specified rate of return on its investment. By ‘cost distribution’, we essentially mean a technology supply curve – i.e. a description of the range of costs across different projects and hence of what volume of generation can be delivered at a given price. We will then use these cost distributions in Chapter 4 to investigate what strike prices might be required to deliver the deployment timelines derived in Chapter 2.

It is important to recognise that there is a time dimension to our cost distributions. The supply curve for projects available to deploy by 2020 will not be the same as that for all projects which could be built by 2030. Moreover, the levelised cost of a project is typically itself a function of time, since we consider how technology costs and required rates of return as a technology matures.

3.1 Methodology

Section 1.3.2 provides an overview of our methodology.

The Committee’s existing levelised cost assumptions are based on a 2011 study by Mott MacDonald[70]. For nuclear, CCS, and biomass conversion our approach is to undertake a literature review of more recent studies, supplemented with conversations with our own in-house experts, to identify where the existing assumptions might be updated. The project pipelines for all of these technologies are characterised by a relatively small number of discrete large projects, and we have mapped costs from the evidence base onto specific projects to derive a detailed supply curve in each case. Using the deployment timelines described above, we are able to incorporate any changes to costs over time (for example resulting from technology learning or de-risking effects).

For onshore and offshore wind a different approach is required since, owing to the relatively large number of projects in the pipeline, the existing evidence base is not sufficiently detailed to allow the construction of a detailed supply curve which captures the full range of projects. In both cases we adopt a more ‘bottom-up’ costing approach based on our in-house expertise. However we then benchmark the resulting cost distribution against the cost ranges available in the evidence base.

Relevant studies published since the 2011 Mott MacDonald study for the Committee include:

- August 2011 study by Parsons Brinckerhoff for DECC on the cost of electricity generation technologies, further updated in August 2012[71] [72];
- Mott MacDonald’s report on biomass conversion of coal plant, for the Committee’s Bioenergy Strategy work[73];
- the Arup work for the RO Banding Review[74];

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70 MML (2011b)

71 PB (2011)

72 PB (2012)

73 MML (2011a)

74 Arup (2011)

- various studies published by the Offshore Wind cost Reduction Task Force[75]; and
- recent and on-going work by the CCS Cost Reduction Task Force[76].

As part of this process we sought the opinion of our own in-house experts, including comments on the various input assumptions for levelised cost calculations (e.g. capital cost, O&M costs, and plant efficiencies) available in the evidence base. However they did not perform their own detailed assessment of costs on a project-by-project basis as this was outside the scope of the study (but see below for the approaches used for offshore and onshore wind).

There is inevitably a high degree of uncertainty in assessing cost distributions of this nature, arising both from the limited time available for the study and from inherent uncertainty about the technology costs involved. There is uncertainty associated with costing a project today, especially so for less mature technologies such as CCS or the next generation of nuclear stations, where there are few or no existing projects. These uncertainties are compounded by uncertainty about how all of these cost components might change over time as a technology matures.

In this study we address this uncertainty by first developing a 'central' cost distribution for each technology and then considering what constitutes a reasonable range for the uncertainty in the various input assumptions to the levelised cost calculation. We then perform sensitivity analysis based on these ranges to determine the impact on the overall cost distributions and hence the potential range of uncertainty associated with the strike prices we derive in Chapter 4[77].

Before looking at each technology in turn, we describe some important concepts that apply to the development of cost distributions for all technologies.

Learning and the concept of FOAK and NOAK

For less mature technologies, the evidence base generally assumes that costs will decrease over time as a result of 'learning'. Cost reductions may derive for example from on-going improvements to the technology itself, from scaling up of the supply chain, or from a 'de-risking' of construction and/or operation leading to investors accepting lower returns.

In this study we take account of the potential for cost reductions in two ways:

- For some technologies we apply 'learning factors' to capital and/or operating costs assumptions, to represent how costs may reduce over time in response the learning resulting from higher deployment. In general we use assumptions in the existing evidence base.
- For nuclear and CCS, we separately define 'First of a Kind' (FOAK), and 'Nth of a Kind' (NOAK) cost assumptions, where FOAK costs represent those applicable to the first deployment of a particular technology and NOAK costs represent the point where further deployment does not significantly affect costs (i.e. where all the 'learning' has occurred).

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75 EC Harris (2012), PWC (2012)

76 CCS CRTF (2012)

77 In this chapter we present only our 'central' cost distributions, but Chapter 4 presents sensitivity analysis for derived strike prices based on uncertainty in input assumptions such as capital cost and discount rate.

Although nuclear power is an established technology, the reactor types put forward by the various developers are new to the UK, and it is around twenty years since the last nuclear construction in the UK. Hence we treat the first reactor built by each developer as a 'FOAK' plant to reflect the fact that each developer will not have any recent experience of building nuclear plants in the UK regulatory environment.

For CCS, we treat the first two pre-commercialisation plants as 'Zero-th of a Kind' (ZOAK), since these are relatively small demonstration projects and are likely to have proportionately higher costs as a result. The next two pre-commercialisation projects (which are larger in scale) are treated as FOAK, and fully commercial plants are treated as NOAK[78].

Discount rate

A key assumption in deriving the levelised cost of a project is the rate of return required by investors (often referred to as the 'discount rate'). A detailed analysis of discount rates is beyond the scope of this study, as we have generally based our assumptions on the existing evidence base. Our starting point was the discount rate analysis undertaken by Oxera for the Committee in 2011[79]. However for some technologies more recent evidence is available – such as a study by PWC for the Offshore Wind Cost Reduction Taskforce[80].

An important goal of introducing CfDs is to reduce the investment risk perceived by investors in low-carbon projects by removing (or at least significantly reducing) electricity market price risk. In this case one would expect investors to accept a lower rate of return than if they were exposed to market price risk – as renewable generators are under the ROC regime, for example. DECC has estimated the size of this impact[81], and we have taken this into account in our discount rate assumptions.

In addition to this specific impact, we more generally assume (as does the existing evidence base) that required rates of return decline over time for a given technology as it matures. A later project is able to benefit from the experience of earlier projects and so investors should become more comfortable that the risks involved can be managed. Hence in general we have assumed a reduction pathway for discount rates as we move through the project pipelines for each technology and the industry is de-risked. Clearly these reductions are dependent on the earlier projects going ahead successfully.

Uncertainty in discount rates is one of the major drivers of uncertainty in our cost distributions, and this is addressed in our strike price sensitivity analysis presented in Chapter 4.

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78 This approach differs slightly from PB (2012), which treats the first commercial projects as FOAK.

79 Oxera (2011)

80 PWC (2012)

81 DECC (2013)

3.2 Offshore wind

3.2.1 Review of evidence base

Relevant studies looking at offshore wind costs published since the 2011 Mott MacDonald[82] study for the Committee include the Arup study for the Renewables Obligation Banding Review[83] and BVG's work for the UK Offshore Wind Cost Reduction Taskforce[84]. Figure 45 in Annex A compares the range of estimates given in these studies for capital cost, operating cost, load factor, and overall levelised cost (as well as comparing with our own estimates derived below). In general capital costs estimates are similar across all studies but operating costs are higher in more recent studies. However Arup suggests slightly lower load factors than Mott MacDonald, so the range of levelised costs is higher at around £150-225/MWh compared to £145-180/MWh for Mott MacDonald (note these are 'current costs' before learning[85]).

3.2.2 Key input assumptions

One of the objectives of this study is to investigate the distribution of costs for wind projects in more detail than in previous studies. Hence for offshore wind we have derived cost distributions drawing on an existing in-house database of UK offshore wind project costs. This has been developed through a 'bottom-up' cost estimation for all uncommitted projects[86], allowing us to take into account specific project cost drivers such as location, depth, distance from shore, and wind conditions and differentiate between projects. The resulting range of costs has been benchmarked against, and is broadly consistent with, other recent studies[87].

Table 7 summarises the range of input assumptions for key drivers of levelised cost whilst a more detailed description of these and how they are derived is provided in Annex A.

Table 7 – Range of assumptions for key cost components to levelised cost calculation

LCOE cost component	Range of assumptions
Capital cost	2.4-3.0 £m/MW
Operating cost	122-214 £/kW/yr
Load factor	40-47%
Operating life	22 years
Build time	3 years
'Current cost' required return	12.4% (pre-tax real)

The ranges shown span the range of projects from the 10th to the 90th percentile values. See Annex A for more detail.

82 MML (2011b)

83 ARUP (2011)

84 BVG (2012b)

85 By 'current cost' we mean the cost for a project reaching financial investment decision in 2013.

86 Where licensed zones will be developed in phases we have considered each phase as a separate project.

87 BVG (2012b) and Arup (2011). See Annex A.

Capital costs are assessed by estimating the supply and installation costs of key sub-systems such as foundations, within-array electrical systems[88], and the wind turbines themselves. For each project we assume a turbine size, informed by developer information where this is public, or else by a view of the project timing. In general, apart from the near term projects, we assume the use of the next generation of larger offshore wind turbines (around 6-7MW). We then assume foundation types appropriate for the turbine size and the depth profile of the site.

Operating costs comprise O&M costs, OFTO costs, and other costs (mainly onshore TNUoS[89] charges and insurance). O&M costs are driven primarily by distance from shore and wave conditions. OFTO costs are derived by estimating the capital cost of the OFTO assets required for each project, then converting these into annual charges payable to the OFTO owner in a manner consistent with existing OFTO licences awarded by Ofgem[90]. TNUoS charges vary according the location of the OFTO landing point, and we assume values projected for 2015 by Redpoint[91].

The overall load factor of a wind farm is a key driver of levelised cost. For each project we derive individual turbine load factors using a database of historic wind data (provided by Anemos) and an assumed wind turbine output curve. The database has a 20km^2 resolution and so allows differentiation between different wind farm locations. This individual turbine load factor is then converted to an overall load factor for each wind farm by adjusting for wake losses, availability, and electrical and other losses.

For all projects we assume a three-year construction period and an operating life of 22 years.

In examining the cost of offshore wind for the recent Renewables Obligation Banding Review, Arup[92] assumes a current required rate of return of 11.6% (pre-tax real, project return) for Round 1, 2, and STW, and 13.2% for Round 3, based on Oxera[93]. We have assumed an average of these values for projects reaching FID before the end of 2015, as it is not clear to us that Round 3 projects are necessarily more risky than projects in earlier rounds. In our view each project has its own unique characteristics such as distance from shore or depth, and it is hard to generalise that Round 3 projects are inherently more risky than other projects.

Compared to projects accredited under the Renewables Obligation, we assume projects developed under the CfD FiT regime face a lower degree of electricity market risk and hence developers should be willing to develop them for a lower rate of return. The size of this impact has been estimated at 1.1-1.2% by DECC[94]. However we have assumed that this benefit is not realised immediately but emerges over time once investors gain

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88 Electrical assets which will be owned by the OFTO, such as the main export cable, are treated as an opex cost.

89 Transmission Network Use of System Charges

90 We assume that the annual OFTO charge is 11% of the estimated capital cost (including interest during construction) of the OFTO assets. The OFTO assets typically include the offshore substation (or convertor station), the main export cable to shore, and the onshore substation (or convertor station).

91 Redpoint (2012)

92 Arup (2011)

93 Oxera (2011)

94 DECC (2013). Note that earlier studies for DECC suggest reductions of 0.6-0.8% (CEPA (2011)) and 0.5-0.8% (DECC (2011c)).

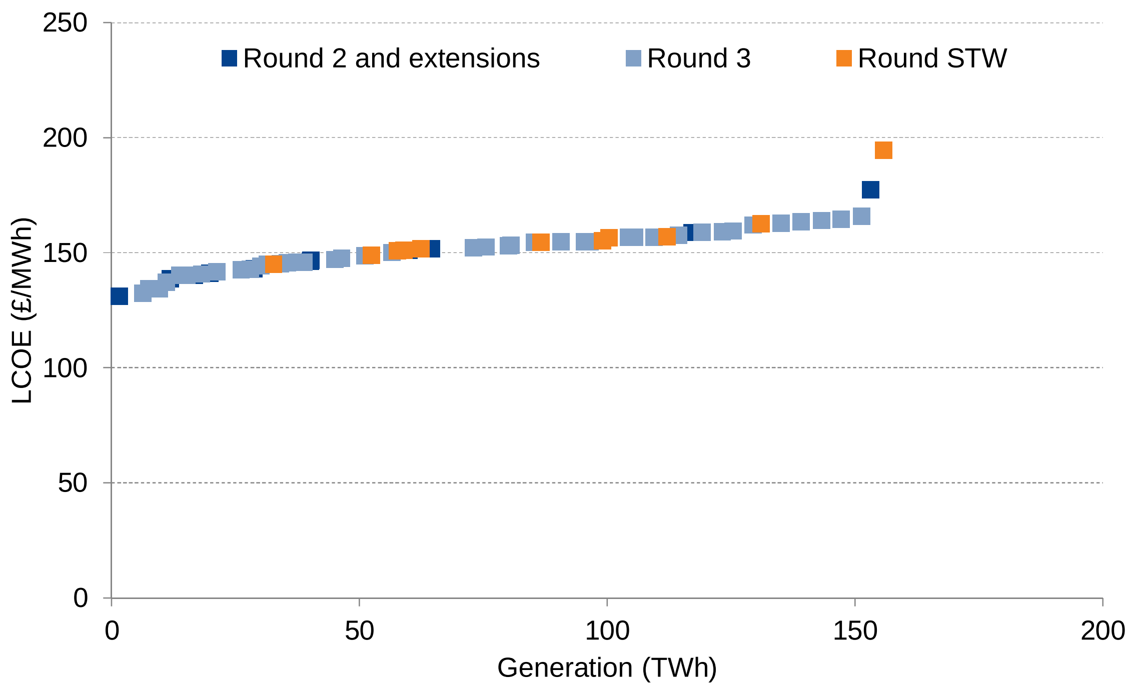
confidence in the new regime. (See Section 3.2.4 for a discussion of how we assume discount rate changes over time.)

3.2.3 'Current cost' supply curve

In Figure 14 we present the resulting cost distribution for offshore wind. At this stage all costs are based on our assessment of 'current costs', i.e. as if the project reached FID in 2013. Our current costs do, however, implicitly assume that the new larger generation of wind turbines is available today. We present this distribution for illustrative purposes only, to show the cost distribution before consideration of how costs might change over time in the following sub-section. Note also that this is our 'base case' cost distribution, based on central assumptions for the various cost components. In Chapter 4 we will consider the impact of cost uncertainty on levelised costs (and hence required strike prices).

Our levelised costs show a range across projects of around £130-195/MWh, with the majority in the range £140-165/MWh. This compares to around £150-225/MWh for Arup (FID 2010), £125-170/MWh for Arup (FID 2015), and £145-180/MWh based on Mott MacDonald 2011 assumptions[95].

Figure 14 – Current cost base case supply curve for offshore wind (£/MWh 2012 money)



Assumed discount rate 12.4%

The supply curve is relatively flat in that a large volume of generation is available within a relatively narrow range of levelised cost. Furthermore, Figure 14 suggests that there is no real pattern in the distribution of costs across projects in different licence rounds. The flatness of the curve also suggests that, because of inherent uncertainty in the various cost components, the relative position of a project within the 'merit order' is uncertain.

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95 Arup (2011) and MML (2011b).

3.2.4 Changes in costs over time

The supply curve shown in Figure 14 is based on current costs before any consideration of future cost reductions due to learning effects – although it does anticipate projects using larger turbines than are currently available. As a next step, we have assumed that both capital and operating costs decline in real time as more capacity is built and the technology matures. A detailed consideration of these technology learning effects is beyond the scope of this study, and we have instead assumed learning rates broadly consistent with existing evidence. Arup[96] assumes a capital cost reduction of 12% and an operating cost reduction of 10% for every doubling of UK capacity. BVG[97] suggests that around half of the capital cost reduction results from economies of scale arising from the introduction of larger turbines. As our current costs already assume larger turbines we assume a further capital cost learning rate of 6%.

In addition, we assume for all projects that the required return is a function of time, or more specifically of the FID date. There are two drivers for this. First, the Government expects that investors should require lower returns under CfD FiTs compared to the current ROC regime because they will not face the same level of electricity market price risk. CEPA assesses this reduction to be around 0.6%-0.8%[98], while DECC analysis assumes 1.1-1.2%[99]. Second, there is an expectation that required returns will decline as the industry matures and gains experience and hence the perceived level of risk associated with offshore wind reduces. Hence we assume that the required return declines to 10.4% in 2017, broadly consistent with PWC's study for the Offshore Wind Cost Reduction Task Force.[100]. In the longer term we assume that the required return declines to just above 9% (see Table 8).

Table 8 – Offshore wind discount rate assumptions

FID date	Required rate of return (pre-tax real)
Up to 2015 (inclusive)	12.4%
2016	11.4%
2017-2019	10.4%
2020 and after	9.1%

Figure 15 shows our cost distribution taking account of both capital and operating cost learning effects, and reductions in required rate of return over time (based on our lower deployment timeline scenario – see Section 2.2.3.1). Compared to Figure 14, the front end of the curve has shifted down considerably such that the cheapest projects have levelised costs close to £100/MWh.

A drawback of a supply curve such as that shown in Figure 15 is that it does not differentiate projects according to the when they come on line in the period up to 2030. Figure 16 shows the supply curve for projects which are available to potentially be

96 Arup (2011)

97 BVG (2012b)

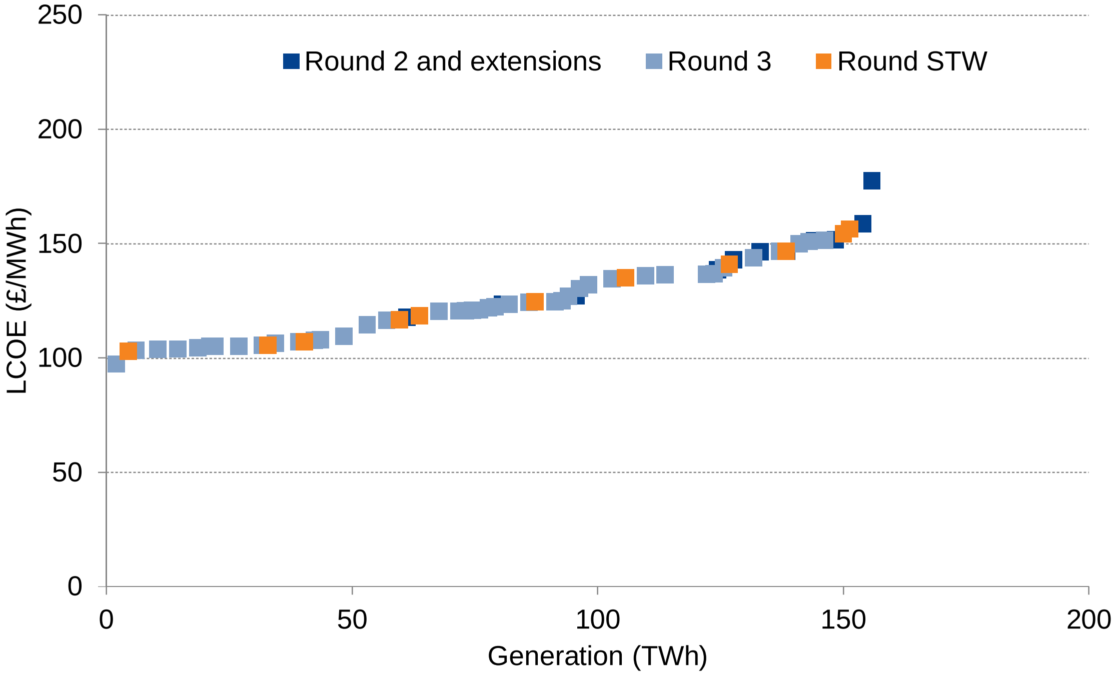
98 CEPA (2011)

99 DECC (2013)

100 PWC (2012)

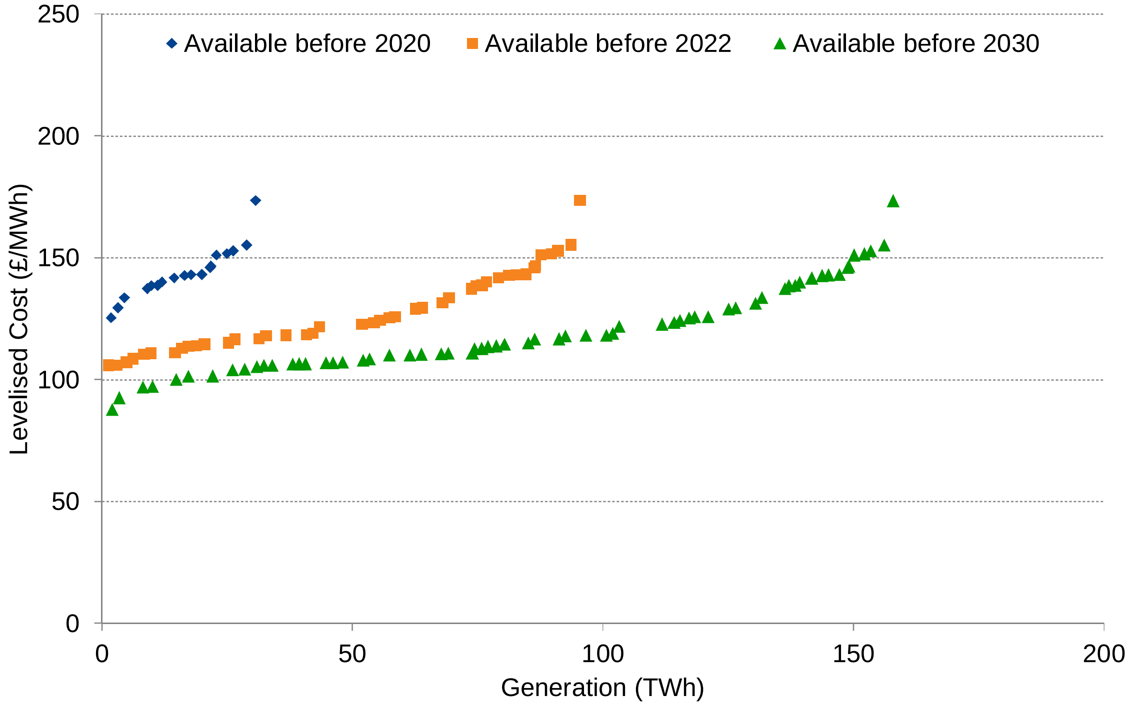
deployed (i.e. commission) at selected intermediate years[101]. Over time the supply of available projects increases. Note, however, that around half of projects are potentially available to commission by 2022. This is because our timeline assumes a large volume of projects submits planning applications in the next few years (see Section 2.2.3.1).

Figure 15 – Base case supply curve for offshore wind with learning effects (£/MWh 2012 money)



[101] Note that the 2030 supply curve in Figure 16 does not quite match that shown in Figure 15. This is because the former is based on the earliest dates by which projects could be deployed, based on assumptions about consenting and construction timescales, whilst the latter is based on when projects are actually deployed in our timeline. This illustrates the point that, based on our methodology, the cost of a project depends on when it is built (and also on how much capacity has already been built).

Figure 16 – Supply curves for intermediate years (£/MWh 2012 money, including learning effects)



See Footnote 101.

The cost distributions presented here are based on our 'central' cost estimates for each offshore wind project. Clearly there is uncertainty around these, and in Chapter 4 we perform sensitivity analysis to investigate the impact of this uncertainty on the range of levelised costs and hence required strike prices. For offshore wind, the largest drivers of uncertainty in levelised costs are uncertainty in capital costs and uncertainty in the required rate of return. For example, an uncertainty range of ±20% in capital cost results in a levelised cost variation of around ±10-15/MWh, whilst increasing the required rate of return by 1% increases levelised cost by around £7/MWh.

3.3 Onshore wind

3.3.1 *Review of evidence base*

As for offshore wind, the Arup study for the Renewables Obligation Banding Review[102] is more recent than 2011 Mott MacDonald[103] study for the Committee. Both show a similar range of 'current' levelised costs – around £80-100/MWh based on Mott MacDonald and around £72-108/MWh for Arup[104].

102 ARUP (2011)

103 MML (2011b)

104 Note that these studies may not be directly comparable as they are based on different FID date assumptions and money bases.

As for offshore wind, one of the objectives of this study is to investigate the distribution of costs for wind projects in more detail than in previous studies. Hence for onshore wind we have derived cost distributions using in-house expertise as described below. Our estimates are compared to the Arup and Mott MacDonald results in Annex A.

3.3.2 Methodology and key input assumptions

For onshore wind the very large number of projects means that it is not practical to assess costs for individual projects. Instead we adopt an approach based on grouping of projects into different cost categories and geographic zones in order to construct a detailed cost distribution reflecting the full range of pipeline projects. The key steps in the analysis are described below, with further detail in Annex A:

- We define nine different project cost categories, differentiated by project capacity and distance from grid, as these variables are considered to be key cost drivers of capital cost[105]. We then derive estimates for capital and operating costs for these project types, based on our in-house engineering expertise and project experience.
- For information on the current pipeline of onshore wind projects, we use a snapshot (taken in January 2012) of projects reported as in planning or consented in Renewable UK's Wind Energy Database. We then assign these projects the nine project categories based on their size and location.
- We also use a project's location to assign it to one of 27 geographic zones corresponding to the latest zones used by National Grid for Generator TNUoS charging purposes[106] [107]. This allows us to capture the geographic variation in grid use of system charges (although, compared to capital costs, grid charges are not a significant driver of levelised cost).
- We also calculate typical load factors for three different turbine heights for (a different set of) fifteen geographic zones, using our database of historic wind data and assumed turbine performance curves. This allows us to assign each project a load factor based on its hub height and location and hence reflect broad geographic variation in load factors. (We also adjust load factors for assumed availability and wake losses at this stage.)
- This allows us to develop a high resolution supply curve for the existing pipeline. For the strike price modelling in Chapter 4 it is also necessary to make an assumption about the cost profile of future projects which have not yet entered the planning system. In the absence of strong evidence on the future evolution of onshore wind costs, we assume that the cost distribution of future projects matches that of the existing pipeline (before the application of any potential learning effects see Section 3.3.4 below). It is possible that costs could increase over time as the better sites (or those where it is easier to obtain consents) are used up; however this might be offset by technology improvements.

Table 9 summarises the range of input assumptions for key drivers of levelised cost whilst a more detailed list is provided in Annex A.

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105 We have not considered possible variation in other capital cost drivers, such as terrain type.

106 NGC (2013b)

107 We also define Northern Ireland as a geographic zone as we consider the full UK pipeline.

Table 9 – Range of assumptions for key cost components to levelised cost calculation

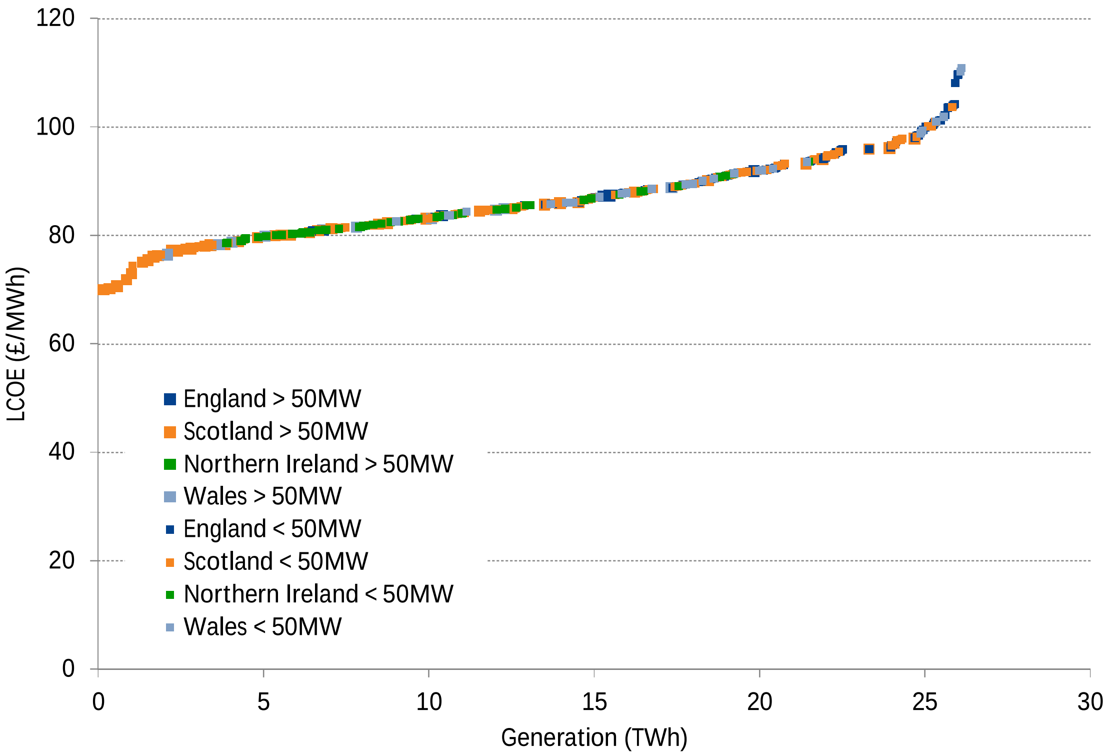
LCOE cost component	Range of assumptions
Capital cost	1.2-1.5 £m/MW
Operating cost	37-73 £/kW/yr
Net load factor	22-31%
Operating life	24 years
Build time	2 years
'Current cost' required return	9.6% (pre-tax real)

Net load factor means after adjustment for availability

3.3.3 Current cost supply curve for existing project pipeline

Figure 17 shows our assessment of the cost distribution of onshore wind projects currently in the project pipeline (either in the planning system or consented but not yet started construction). It does not include projects below 5MW as these will not be eligible for CfDs – these projects represent less than 1TWh per annum in total, but many have relatively high levelised costs of over £100/MWh owing to their smaller size.

Figure 17 – Current cost base case supply curve for existing onshore wind pipeline



Scottish projects represent the largest amount of generation and are generally amongst the cheaper projects. Projects in Wales and Northern Ireland are in similar cost ranges, although there are no projects greater than 50MW in the current pipeline in Northern

Ireland. English projects are generally more expensive due to low load factors and relatively low project capacities.

The majority of projects have levelised costs in the range £80-100/MWh, although some projects (typically large projects in Scotland) are below £80/MWh (the full range is around £70-110/MWh). Figure 46 in Annex A shows that the range of levelised costs we have derived is broadly consistent with the Arup and Mott MacDonald ranges, given the uncertainties involved.

The supply curve shown in Figure 17 consists of close to 400 individual projects. For modelling of strike prices in Chapter 4 we have aggregated these into a smaller number (64) to keep the modelling manageable. Figure 18 shows this aggregated curve. Whilst Figure 17 shows the cost distribution we have derived for the existing pipeline, Figure 18 also shows costs (albeit 'current costs') for the full volume of potential projects, including new projects entering the planning system between now and 2030. Our timeline suggests that this volume is roughly equivalent to the existing pipeline volume. In the absence of strong evidence on the future evolution of onshore wind costs, we assume that the cost distribution of future projects matches that of the existing pipeline.

3.3.4 Changes in costs over time

Reductions in the levelised cost of energy generated from onshore wind as a consequence of a learning effect are difficult to predict and can be dwarfed by external volatile factors such as commodity price fluctuations. Cost reductions could be achieved for example if more diverse equipment suppliers, particularly from India and China, gain a foothold in the UK market. The 2011 Mott MacDonald study for the Committee[108] acknowledges onshore wind as a 'mature' technology in a market that is 'reasonably balanced'. It states that 'the general consensus is that there will be no dramatic change on the horizon' for onshore wind costs. However, the report also sets out a 10-15% cost reduction to 2021 and 20-25% to 2040 from 2011 levels – deemed to be consistent with a 10% learning rate applied to capital costs. The UK Renewable Energy Roadmap[109] envisages costs falling from £75-£127/MWh in 2010 to £71-£122/MWh in 2020 after a tripling in capacity (an approximate learning rate of 1.6%).

Due to the uncertainty over learning rates in onshore wind, our base case supply curve has been developed with no capital cost (or operating cost) learning presumed up to 2030 in the UK. In our sensitivity analysis in Chapter 4 we investigate the impact of potential capital cost learning rates of 6% and also 8% on required strike prices.

We do, however, assume discount rates will decline further over time, in particular to reflect the lower market risk for projects awarded CfDs (compared to projects receiving ROCs). We phase in this reduction over time, such that the required rate of return declines from an initial value of 9.6% (pre-tax real) to 9.1% for projects reaching FID in 2017 or after (Table 10). The effect of this reducing discount rate can be seen in Figure 19. There is a slight reduction in levelised costs at the front end of the curve, but this is small owing to the relatively small discount rate reduction.

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108 MML (2011b)

109 DECC (2011a)

Figure 18 – Current cost base case supply curve for full onshore wind pipeline

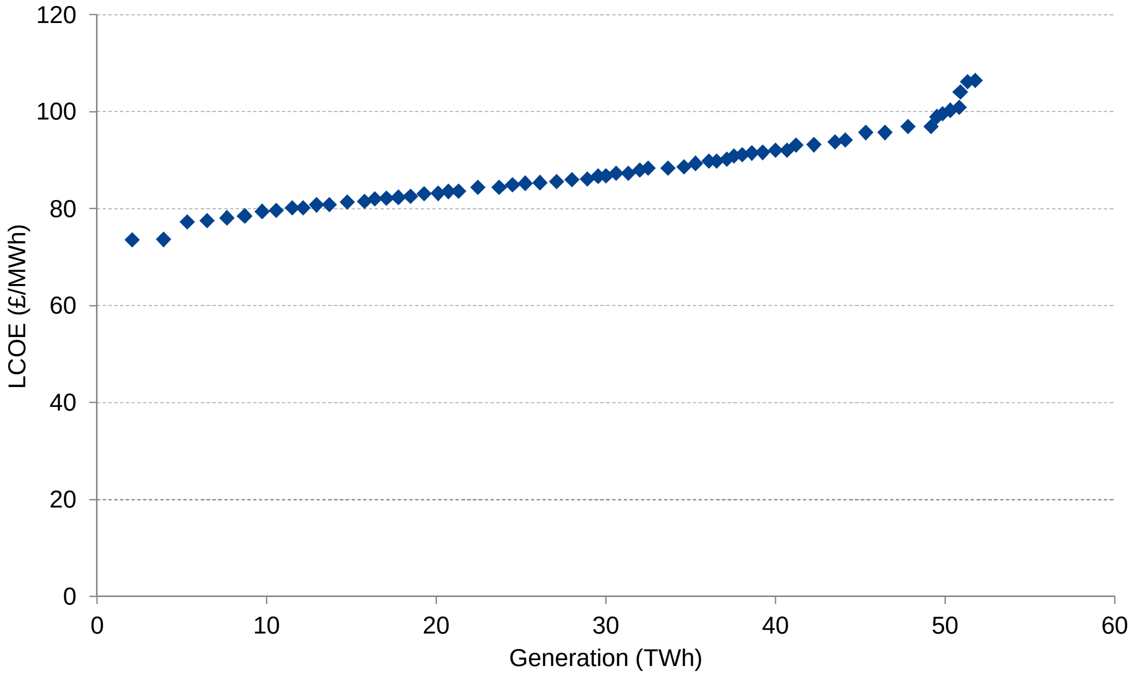


Figure 19 – Base case supply curve for onshore wind with reducing discount rate

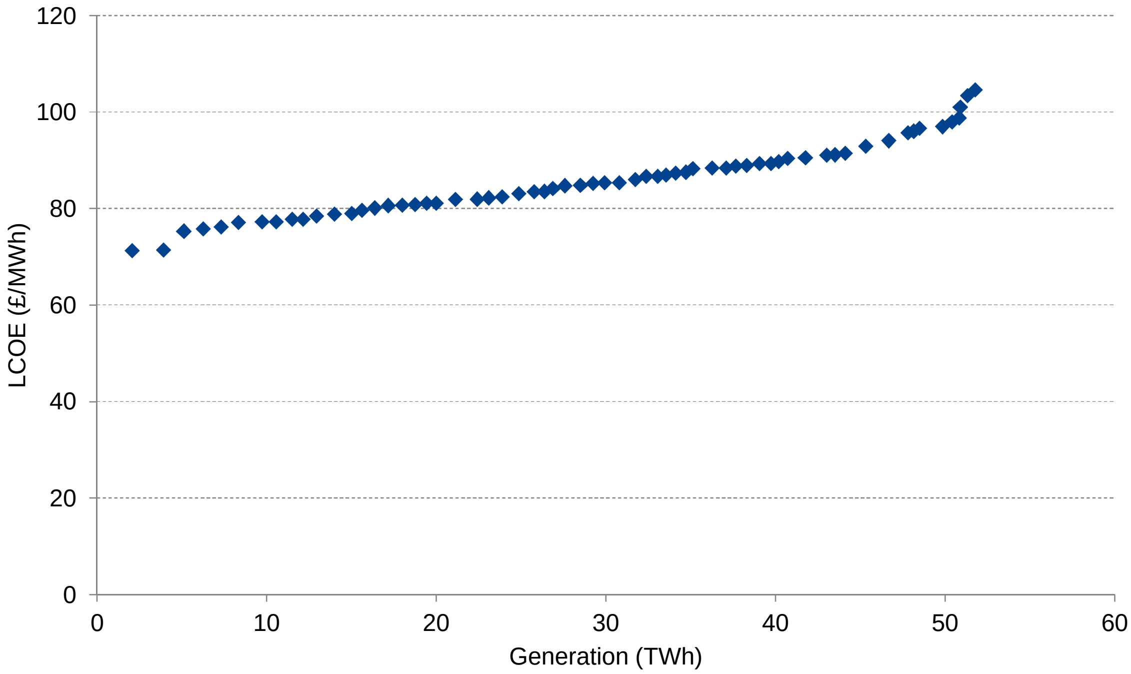


Table 10 – Onshore wind discount rate assumptions

FID date	Required rate of return (pre-tax real)
Up to 2015 (inclusive)	9.6%
2016	9.4%
2017 and after	9.1%

3.4 Nuclear

Compared to onshore and offshore wind, we have adopted a very different approach for developing a cost distribution for nuclear projects. This is based on assessment of the existing evidence base and mapping the relevant cost assumptions presented in this onto the discrete projects in our deployment timeline. In addition to reviewing existing studies we have considered anecdotal information from industry press, the view of our in-house nuclear engineering experts, and information stemming from informal discussions with industry players.

3.4.1 Review of evidence base

As a starting point we adopt the latest estimates of nuclear generation costs published by Parsons Brinckerhoff (PB) for DECC in 2012[110], as we consider this to be more up to date than the 2011 Mott MacDonald study currently used by the Committee for its levelised cost modelling. We see no strong reason to depart from the PB assumptions on FOAK capital cost, operating cost, and lifetimes for First of a Kind (FOAK) projects. Similarly we generally also adopt the PB assumptions for Next of a Kind (NOAK) projects, subject to a few points described in more detail below. The PB studies considers only the costs associated with the PWR reactor and we have examined the relevance of these assumptions with reference to a BWR and developed our own high level thinking on the potential cost differences.

3.4.2 Key input assumptions

Annex A provides a detailed review of the input assumptions we have used to derive our cost distributions, whilst Table 11 summarises these. Some areas of particular significance are discussed below.

110 PB (2012)

Table 11 – Range of assumptions for key cost components to levelised cost calculation

LCOE cost component	PWR		ABWR	
	FOAK	NOAK	FOAK	NOAK
Pre-development costs (£m/MW)	0.10-0.41	0.09-0.35	0.13-0.51	0.11-0.43
Construction cost (£m/MW)	3.5-4.1	3.0-3.5	3.0-3.5	2.5-3.0
Fixed operating cost (£/kW/yr)	72-101	62-87	72-101	62-87
Variable operating cost (£/MWh)	9-12	9-12	9-12	9-12
Load factor (%)	90 - 92	90 - 92	75 - 90	75 - 90
Operating life (years)	60	60	60	60
Pre-development time (years)	5 - 7	5 - 7	4 - 6	3 - 5
Build time (years)	5 - 8	5 - 8	4.5 - 7	4 - 6

See below for comments on ABWR assumptions

ABWR technology

The 2011 Mott MacDonald study for the Committee does not highlight any significant cost differences between the EPR and BWR reactors, although it does suggest that the simpler nuclear island used in the BWR is likely to deliver a modest cost advantage. The PB study for DECC shows cost estimates only for the PWR (without distinguishing between the Areva EPWR and the Westinghouse-Hitachi AP-1000) and does not include BWR estimates. We have assumed that both PWR reactor types have the same cost estimates – we recognise that construction aspects at the plants are different but have no information to judge whether this has any impact on commercial pricing.

Hitachi's ABWR is a relatively mature technology in comparison having been deployed in Japan at a number of sites. Based on our engineering expertise we have adopted lower cost assumptions for ABWR compared to PWR due to: fewer major nuclear island components; an established engineering design development and manufacturing supply chain for a mature technology; and a shorter construction time. The reduction in cost is principally determined by the reduction in assumed construction time. However it should be recognised that the ABWR assumptions are less certain than the PWR assumptions (which are themselves uncertain) owing to a smaller published evidence base.

FOAK vs NOAK and learning assumptions

Previous studies of forecast new nuclear build costs have included reductions in follow-on build of nuclear units, attributable to lessons learned and the reduction of a 'market congestion' premium[111]. DECC assume (based on PB analysis) an indicative rate of learning which delivers a 5% cost reduction for each global doubling of capacity and we adopt DECC's approach here.

We examined the timing of UK and international new build and conclude that a market premium, if it occurs will affect the costs of later rather than early unit(s), as projects start to overlap. In many respects therefore the advantages of learning as the UK supply chain rebuilds its experience and knowledge, and trained capacity grows, may be off-set by demands on the labour force. We observe that historically the UK was able to sustain construction of 4 reactor units in the AGR programme of the 1970's, but have no

111 MML (2011b), PB (2012)

indication of the impact on costs from simultaneous activities at diverse sites. We also note the scale of construction activity for the London 2012 Olympics, as demonstration of the scale of construction projects delivered by the UK.

One particular feature of a nuclear new build project is its international dimension; and the scope and scale of UK supply chain involvement. The reactor designer (and hence much of the pre-construction design effort) will be foreign, together with the supply of a number of large high quality components (such as reactor pressure vessel, steam generators, turbine-generator shaft). All of the designs proposed for UK deployment before 2030 (i.e. assessed by GDA) will be able to draw from construction experience elsewhere, and from an international dimension are therefore on the way to NOAK for non-UK sourced items.

We have separated UK and non-UK costs based upon interpretation of reported data in the US. We estimate that 30-35% of costs will be associated with established non-UK supply (covering nuclear island and major turbine island equipment, and 50% of designer/ technical/ supervision costs) and therefore not subject to UK-specific learning, and the remainder (civil construction, remaining ME&I manufacture and installation labour and local office functions) will be UK-specific and subject to UK learning as experience develops.

Based on these considerations, we assume that the first reactor built by each developer in the UK is based on our FOAK cost assumptions. We also take account of PB's learning rate assumptions which show FOAK capital costs declining over time based on experience gained elsewhere in the world. This learning effect is mostly applied to FOAK costs as by definition NOAK represents the point in time when costs are unlikely to be changed through the deployment of another plant. Subsequent reactors built by each developer trend towards NOAK costs.

Discount rate

We have assessed the rate of return required for each project on a project-specific basis taking into account the when a project reaches FID date according to our timeline and the experience of the developer at that point (see Table 12). For example, we assume the Moorside project reaches financial close once the first EDF PWR units are operating, and that investors will accept a lower rate of return at this point. (Note that these are our assumptions for discount rate and may not correspond to hurdle rates actually required by developers).

Table 12 – Nuclear discount rate assumptions

Developer	Station	Required rate of return (pre-tax real)
EDF	Hinkley Point	11.0%
EDF	Sizewell	10.2%
Horizon	Wylfa (first 2 units)	11.0%
Horizon	Oldbury	9.2%
Horizon	Wylfa (third unit)	9.2%
NuGen	Moorside	9.2%

3.4.3 Nuclear supply curve

The supply curve presented is based on the project pipeline described in section 2.4.3 and the central cost assumptions listed in Table 20 (in Annex A). Whilst Figure 20 shows

a progression of projects in order of cost, it should be noted that in general the cheaper projects can only be accessed through the construction of the more expensive projects – as indicated by Figure 21 which displays projects in order of their FID year. Step change in cost profiles can be seen between the two nuclear technologies, with the ABWR assumed to be a cheaper option, and also as plants transition from the FOAK cost profile to NOAK and discount rates reduce as outlined above. We also see the FOAK plants deployed in later years showing a fall in levelised cost estimates as they benefit from both domestic and international learning experiences.

Based on our assumptions, our base case (central cost) estimate for the levelised cost of the first reactors at Hinkley Point is around £92-94/MWh. (This should not be confused with the required strike price, which might be different from this for reasons explained in Chapter 4.) Based on our analysis, NOAK costs for PWR fall to around £72-75/MWh for the later projects.

Our base case (central cost) estimated levelised cost for the first reactors at Wylfa, assuming FID in 2018-2020, is £80-82/MWh. Based on our analysis, this falls to around £65/MWh for later ABWR reactors.

Note that Figure 20 and Figure 21 are based on our central cost estimates for each project. The major uncertainty in levelised costs derives from uncertainty in capital cost and discount rate assumptions, as these are the key drivers of nuclear costs. Chapter 4 shows the sensitivity of our derived strike prices to these uncertainties. Note also that our cost estimates are based on generic cost assumptions each reactor type and do not take account of site-specific factors.

Figure 20 – Nuclear supply curve by cost order

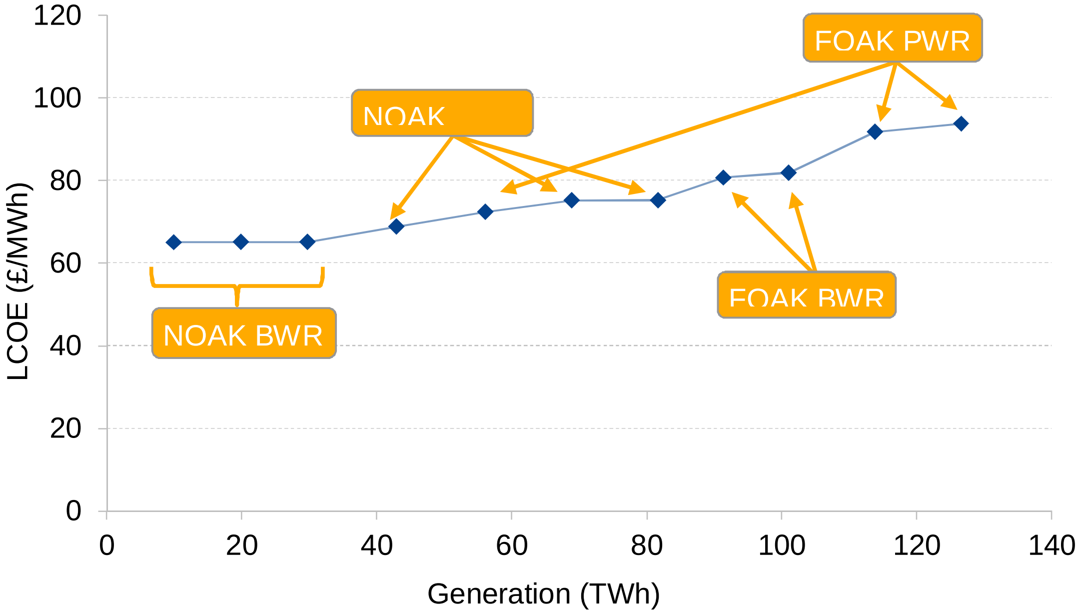
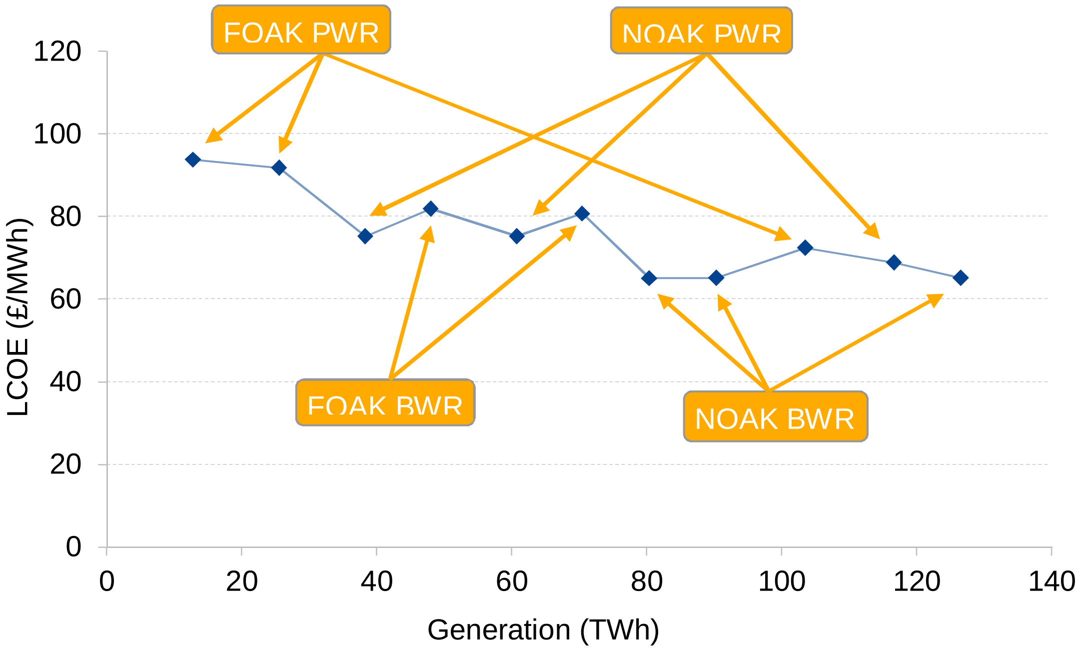


Figure 21 – Nuclear supply curve in order of FID year



3.5 CCS

Compared to other technologies addressed in this study, CCS is perhaps the most complex owing to fact that CCS may be based on gas or coal as fuel and may employ one of a number of capture technologies. In addition CCS is the least mature of the technologies and so the uncertainties are greater.

3.5.1 Review of evidence base

As for nuclear, our approach for developing a cost distribution for CCS projects is based on assessment of the existing evidence base and mapping the relevant cost assumptions presented in this onto the discrete projects in our deployment timeline. This includes the work of the UK CCS Cost Reduction Task Force, with which we have been involved. The Task Force published an Interim Report in November 2012 on the potential for reducing the costs of CCS in the UK[112] – this includes cost estimates based on a 2012 Mott MacDonald study for DECC[113] (with some adjustments).

Again as for nuclear, our starting point is to adopt the latest estimates of nuclear generation costs published by Parsons Brinckerhoff for DECC in 2012[114], as this is more recent than the 2011 Mott MacDonald study on which the Committee has previously based its analysis[115]. In Annex A we compare values for the key cost assumptions in each of these studies.

It is not straightforward to compare UK CCS Cost Reduction Task Force evidence and the Parsons Brinckerhoff study as the former assesses costs by FID date and the latter uses the FOAK/NOAK concept. However we believe the two are broadly consistent in relation to levelised costs of FOAK and NOAK plant. (The Parsons Brinckerhoff data does not apply to pre-commercial CCS projects, and we outline below how we have addressed this.)

3.5.2 Key input assumptions

We derive levelised costs for the five different carbon capture technologies assessed by Parsons Brinckerhoff as follows[116]:

- coal – integrated gasification and combined cycle (IGCC) with CCS;
- coal – advanced supercritical boiler (ASC) with oxy combustion CCS;
- coal – ASC with post combustion CCS;
- gas – combined cycle gas turbine (CCGT) with pre combustion CCS; and
- gas – CCGT with post combustion CCS.

Table 13 summarises the input assumptions we have used to derive our cost distributions for these technologies. Annex A provides more details, whilst some areas of particular

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112 CCS CRTF (2012)

113 MML (2012)

114 PB (2012)

115 MML (2011b)

116 We have not considered the cost of retrofitting existing coal and gas power stations with capture technology.

significance are discussed below. The values in Table 13 are our 'central cost' assumptions (based on Parsons Brinckerhoff), and ranges show the range of FOAK and NOAK values (see below for discussion of pre-commercial plants and Annex A for further details on NOAK/FOAK values).

Table 13 – Range of assumptions for key cost components to CCS levelised cost calculation

LCOE cost componet	Coal IGCC	Coal oxy-fuel	Coal post-combustion	Gas pre-combustion	Gas post-combustion
Total capital cost (£m/MW)	2.4-2.5	2.3-2.4	2.8-3.0	1.4-1.6	1.2-1.4
Fixed operating cost (£/kW/yr)	63-69	60-65	72-86	34-40	28-33
Fuel costs	Based on DECC Updated Energy and Emissions Projections (DECC 2012d)				
CO2 transport and storage costs (£/te)	12	12	12	12	12
Other variable operating costs (£/MWh)	2.0-2.3	2.3-2.4	2.1-2.5	1.2-1.5	1.6-1.9
Efficiency (HHV)	32-33%	33-34%	32-33%	38%	46%
Availability	90%	90%	96%	93%	93%
Operating life (years)	25-30	25-30	25-30	25-30	25-30
Pre-development time (years)	5-6	4-5	4-6	4-7	4-8
Build time (years)	4-5	4-6	4-5	4-5	4-5

Transport and storage costs

The Parsons Brinckerhoff study treats transport and storage (T&S) as a variable charge on the operation of the plant. We adopt the latest estimates quoted in the 2012 PB study of central charge of £11.9/tCO_2 (within a range of £7.9-16.9/tCO_2).

However it is important to note that this approach assumes a fully developed transport and storage infrastructure which has commoditised the safe removal of carbon from capture plants. If this is not the case, then the assumption is that the cost of developing a full-scale T&S infrastructure is not borne disproportionately by early projects, but rather that Government adopts policies which spread the costs of this infrastructure evenly across all users.

Based on the PB assumptions we calculate a base case T&S charge of approximately £5/MWh for a gas post combustion capture plant and around £10/MWh for a coal oxy capture plant. This compares with the lower end of cost estimates published by the CRTF which are available once the T&S infrastructure has been developed. Developing an estimate of the cost of developing the transport and storage infrastructure was beyond the remit of this study but it is worth noting that the challenge of developing widespread CO_2 transport and storage infrastructure must be overcome to validate the cost estimates and deployment timelines presented in this report.

Discount rate

CCS is relatively unproven compared to the other low-carbon technologies considered in this study. Hence we assume a high discount of 15% for the first pre-commercial projects, in line with Oxera[117]. Our timeline assumes a concerted and successful policy effort to commercialise CCS, including measures to provide T&S infrastructure on a 'commoditised' and de-risked basis to CCS generators. Hence we assumed the return required by investors declines over time to 10% for commercial projects deployed in the late 2030s following successful pre-commercialisation projects (Table 14). Again this is

117 Oxera (2011)

consistent with Oxera. Clearly this assumption of declining discount rate is dependent on successful demonstration and de-risking of CCS during the pre-commercial phase.

Table 14 – CCS discount rate assumptions

Project description	Required rate of return (pre-tax real)
First pre-commercial phase (ZOAK)	15.0%
Second pre-commercial phase	13.0%
First FOAK project per sub-technology	12.0%
Subsequent commercial projects with FID date up to 2025	11.0%
Subsequent commercial projects with FID date from 2026	10.0%

ZOAK cost assumptions

The Parsons Brinckerhoff study does not assess the costs of the first (pre-commercial) CCS projects. Given that these demonstration projects are likely to be relatively small compared to full-size commercial projects, we expect these 'zero-th of a kind' (ZOAK) projects to be significantly more expensive than the first (FOAK) commercial projects. The UK CCS Cost Reduction Taskforce takes this into account by looking in detail at costs for these early projects[118].

In this study we adopt a simpler approach of increasing capital costs by 50% compared to the equivalent FOAK values but still charging T&S costs as a 'commoditised' service. In reality, it is possible that T&S charges for the pre-commercial projects will be higher than the long term value associated with a fully developed infrastructure (depending on how the Government chooses to develop this infrastructure), and our higher capital costs for ZOAK plants reflect an additional contribution to T&S infrastructure[119]. (We compare our levelised costs for ZOAK plants with the CRTF study in Section 3.5.3 below.)

3.5.3 CCS supply curve

The cost distribution we have derived is based on the project pipeline described in Section 2.5.3 and the central cost assumptions described above. Whilst Figure 22 shows a progression of projects in order of cost, it should be noted that in general the cheaper projects can only be accessed through the construction of the more expensive projects as indicated by Figure 23 which displays projects in order of their FID year. The wide variation between projects is explained by the choice of a range of capture technologies for these projects – coal projects are generally significantly more expensive than gas.

Levelised costs for the pre-commercial plants are generally in the range £120-160/MWh (where gas plants represent the lower end of this range and coal plants the upper end). This compares to estimates by the UK CCS Carbon Reduction Task Force of around £145/MWh for early gas CCS plants and £165-170/MWh for early coal CCS plants. It is possible that the difference stems from our assumption of commoditised T&S costs even for these early plants (see discussion in the previous section).

118 CCS CRTF (2012)

119 In addition, the £1bn of funding made available by the Government for the CCS Commercialisation Programme Competition could be used to bring down T&S costs for the first phase pre-commercialisation projects to a level consistent with a fully developed T&S infrastructure. (Note also that in our strike price modelling in Chapter 4 we do not take account of this funding.)

For the commercial projects we have generally selected post-combustion gas, as this is the cheapest capture technology based on our assumptions. The cost of these projects is around £90-100/MWh, where much of the reduction is driven by reduced discount rate assumptions. We have also selected two coal-based projects for the commercial phase – these have estimated levelised costs around £110-120/MWh.

As for nuclear, uncertainty in capital cost and discount rate assumptions is a key driver of uncertainty in levelised costs. However the largest driver of uncertainty is fuel price uncertainty as fuel costs represent a significant proportion of the overall levelised cost. For our central cost assumptions we have taken fuel price assumptions from DECC's 2012 Updated Energy and Emissions Projections – Chapter 4 shows the sensitivity of our derived strike prices to fuel prices.

Figure 22 – CCS supply curve with increasing costs

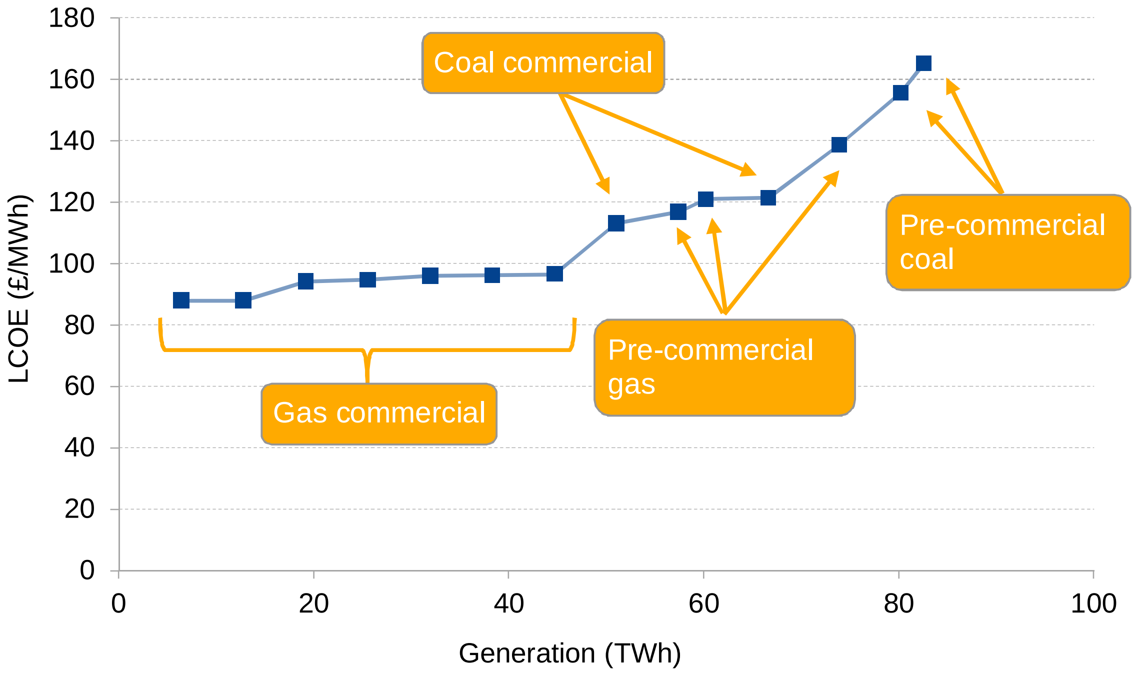
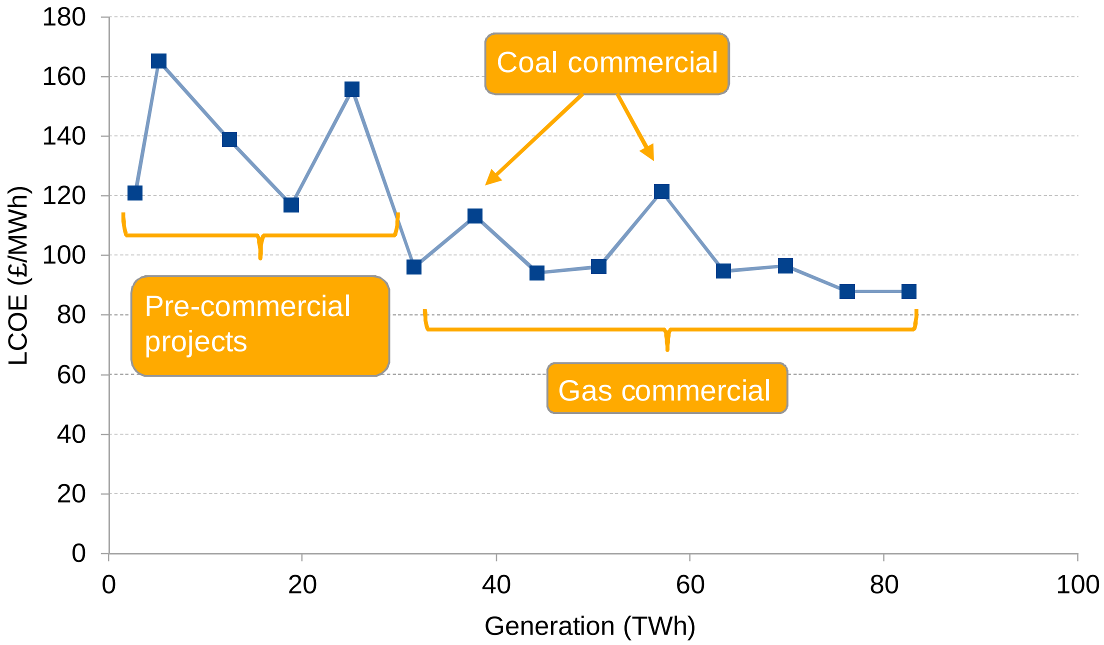


Figure 23 – CCS supply curve in order of FID year



3.6 Biomass conversion

3.6.1 Review of evidence base

For biomass conversions, we have based our cost assumptions on previous work for the Committee by Mott MacDonald[120]. This comprised a desktop assessment of capital and operating costs on a station-by-station basis. However its scope did not include a detailed site-specific costing of conversion costs and so capital costs differentiation is based solely on economies of scale considerations rather consideration of station-specific engineering issues. There is some differentiation in operating costs, for example as a result of station-specific assumptions for efficiency, economies of scale in O&M, and fuel delivery costs.

In deriving levelised costs for biomass conversion projects we have considered only those projects which proceed based on our timeline presented in Section 2.6.3. In addition we have not considered those units which have already been converted under the Renewables Obligation and therefore which we have not considered to be candidates for CfDs (Ironbridge, Tilbury, and the first Drax unit). The Mott MacDonald study suggests that the full supply curve is relatively flat as there are a large number of similar stations with similar costs – these are the stations based on 500MW units (and disregarding plants which are opted out of LCPD and likely to close shortly). Hence a different choice of conversion projects from amongst these stations will not significantly impact the resulting cost distribution.

We have reviewed the Mott MacDonald assumptions and generally see no reason for departing from them, as we believe it is not possible to be more precise or introduce more differentiation across projects without significant additional work. Furthermore the assumption for biomass price (which is a key driver of the levelised cost of converted plant) appears reasonable based on our own understanding of the global biomass market. Clearly however, there is uncertainty in these cost assumptions, and these are explored in Chapter 4 by testing the sensitivity of derived strike prices to input cost assumptions.

3.6.2 Overview of assumptions

Hence our resulting assumptions for the key cost components for biomass conversion, derived from the Mott MacDonald work, are as follows:

- We assume all conversions result in a capacity down-rating of 30% and a 4% loss in efficiency[121].
- Capital costs ranges from around £250/kW (of down-rated capacity) to around £450/kW, where the higher end of this range corresponds to smaller coal stations[122].
- Fixed O&M costs range from around £30/kW/yr (based on down-rated capacity) to around £70/kW/yr, where again the high end of the range corresponds to the smaller station. Non-fuel variable O&M costs are assumed to be £1.50/MWh.
- The price of wood pellets delivered to the UK is assumed to be in the range £6-8/GJ[123]. A small adjustment (positive or negative) is then made to account for small differences in delivery cost to specific power station.

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[120] MML (2011a)

[121] In other words efficiency reduces to 96% of assumed efficiency running on coal.

[122] Note however that the Mott McDonald approach does not take into account other station-specific factors affecting conversion costs

- We assume a 15 year operating life based on the proposed CfD duration. (Mott MacDonald assumed 10 years).

Based on Mott MacDonald, we have assumed an annual load factor of 90% – i.e. that converted plants are able to run baseload. It was beyond the scope of this study to model plant despatch, but previous work for the Committee by Redpoint[124] suggests that around 80% might be more realistic. We have retained 90% here for consistency with Mott MacDonald, but a quick sensitivity analysis suggests the difference between the two is only around £1/MWh in levelised cost terms – this is because the levelised cost of biomass conversion is dominated by variable fuel costs.

We assume a required rate of return of 10% (pre-tax real) again based on the Mott MacDonald study.

3.6.3 Supply curve

Figure 24 shows the cost distribution we have derived for biomass conversions, by cost order and by date of conversion (based on our central cost assumptions). As for nuclear and CCS, we have only shown costs for those projects which proceed based on our timeline.

Levelised costs generally lie in the range £80-90/MWh – the key message here is that the cost distribution is relatively flat because most projects are very similar in nature. There is one project at around £100/MWh – this is a smaller project with relatively high capital and operating costs per unit of capacity.

The key drivers of cost for biomass conversions are fuel cost, capital cost, and load factor. The most dominant of these is fuel price, where moving from our central assumption to our high or low assumptions for fuel price changes the levelised cost by around ±£10/MWh.

123 This compares to an assumed range of around £7-9/GJ in DECC's Impact Assessment for its Response to the Renewables Obligation Banding Review (2012e).

124 Redpoint (2012b)

Figure 24 – Biomass conversion supply curve with increasing costs

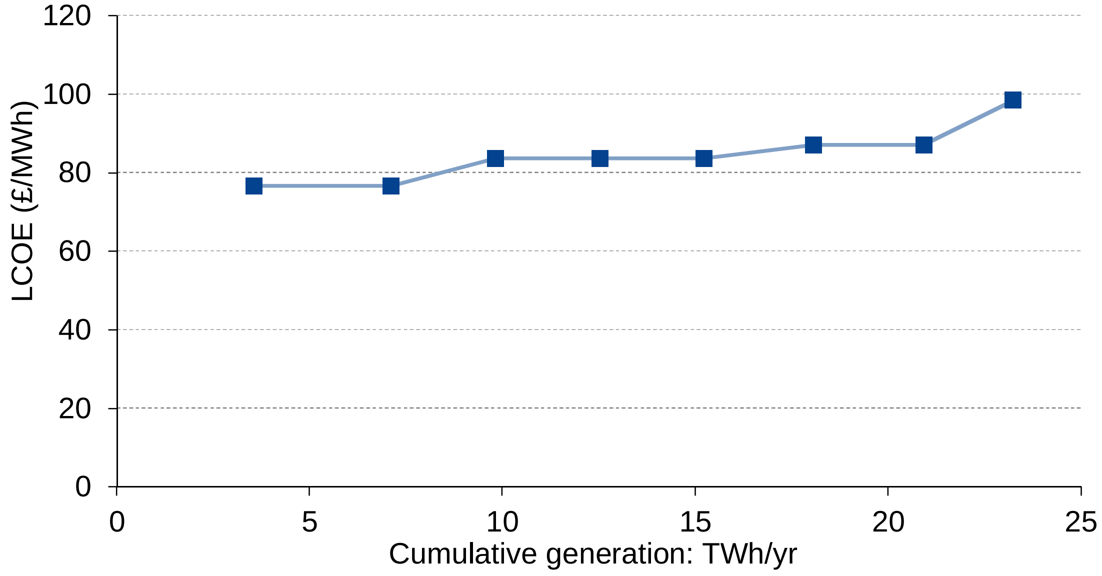
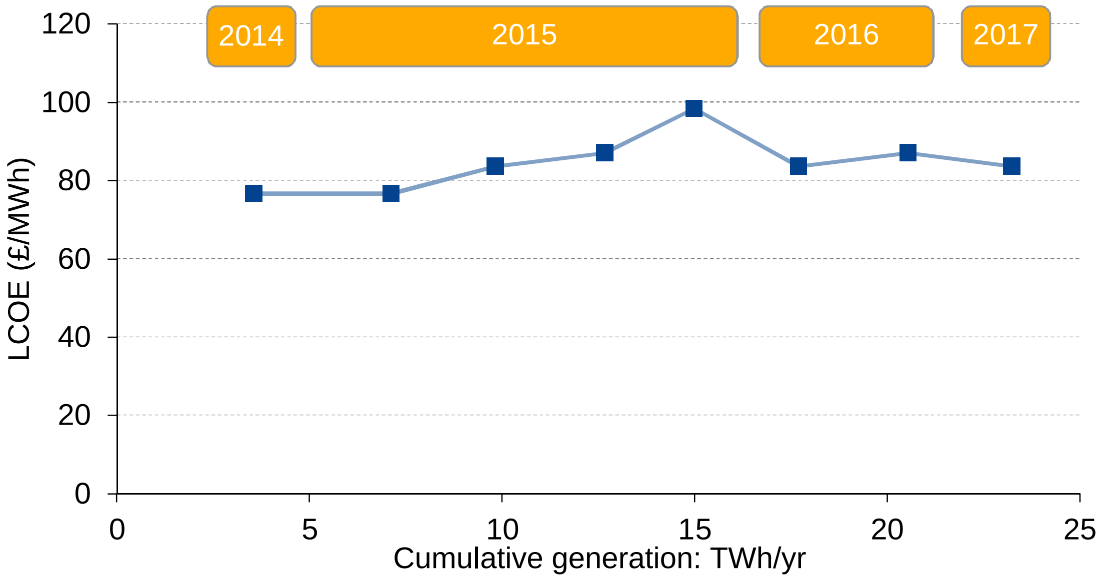


Figure 25 – Biomass conversion supply curve in order of FID year



3.7 Key messages

In this chapter we have developed detailed cost distributions for each of the five low-carbon technologies, including taking account of how costs might change over time.

There is a high degree of uncertainty in estimating costs, both because of uncertainty about the 'current cost' of a project and uncertainty about how this might change over time as a result of technology learning and of changing rates of return required by investors in response to changing perceptions of project risk.

In general our cost assumptions do not depart significantly from the existing evidence base, given the uncertainty involved (although where available – for nuclear and CCS – we use more recent data than the 2011 Mott MacDonald study for the Committee). For onshore and offshore wind we derive our own cost assumptions but we believe the resulting levelised costs for these are broadly consistent with other studies, again recognising the uncertainties involved. Our cost assumptions span a more detailed range of projects than previous studies by attempting to capture some of the differences between projects (but we have not performed detailed engineering cost assessment for each project).

Our key messages for the individual technologies are as follows:

Offshore wind

- The cost distribution for offshore wind is relatively flat, with the majority of projects showing 'current costs' in the range £140-160/MWh.
- It is very difficult to generalise about which projects are cheaper and which are more expensive, for example by leasing round or location.
- Costs fall significantly over time as a result of learning and reducing discount rates. Levelised costs approach £100/MWh but generally remain above this level.

Onshore wind

- Based on our analysis, the levelised cost of the existing pipeline of onshore wind projects (above 5MW in capacity) is in the range £70-110/MWh, with the majority in the range £80-100/MWh.
- In general projects are cheaper if they are above 50MW in size or if they are in Scotland. Based on our analysis, much of the capacity which we estimate to have a levelised cost below £80/MWh falls into both of these categories.
- Compared to offshore wind, the potential for future cost reductions through learning or reduced discount rates is much lower.

Nuclear

- We base our cost assumptions for nuclear power on the latest Parsons Brinckerhoff study for DECC[125]. We assume ABWR is slightly cheaper than PWR.

125 PB (2012)

- Costs fall significantly over time as a result of learning and reducing discount rates. Levelised costs approach £65-75/MWh for the NOAK plants coming available around 2030.

CCS

- In general gas CCS appears cheaper than coal CCS. However given the uncertainties involved, it is difficult to form a firm view as to which of the sub-technologies for a given fuel is cheapest.

- There is uncertainty over which technology (if any) will emerge as the dominant technology following the pre-commercialisation phase. However we assume costs will reduce significantly for the successful technologies, driven in particular by reducing discount rates.

- Our cost distributions also assume that CO_2 transport and storage costs are essentially ‘commoditised’, meaning that there is a well-developed T&S infrastructure which reduces the risk of individual CCS projects by insulating them form wider T&S infrastructure risks.

Biomass conversion

- Most biomass conversion projects have a similar cost since the existing coal fleet comprises a number of similar stations. There will be some differences based on plant size and fuel logistics, and the condition of the existing station (although this is hard to determine).

4. IMPLICATIONS FOR STRIKE PRICES

In this Chapter we present our analysis of CfD strike prices required to bring forward the deployment described in Chapter 2 given the technology cost distributions derived in Chapter 3.

4.1 Methodology

Our starting point for the analysis is the timeline derived for each technology in Chapter 2, which sets out plausible deployment profiles for each technology to make a significant contribution to decarbonising the electricity sector. We then use the cost distributions developed in Chapter 3 to assess the level of CfD strike prices likely to be required for each technology to bring forward deployment in line with the projected deployment timeline.

To do this we develop a modelling tool which:

- calculates the strike price which each potential given project would require to earn its desired return[126];
- selects from the potential projects available in each year to meet the timeline deployment for the year[127], based on the cheapest projects first; and
- determines the strike price received by each project based on when it is actually deployed.

For nuclear, CCS, and biomass conversions, our timelines already make assumptions about which projects are deployed and so deriving strike prices from the cost distributions is relatively straightforward.

For onshore and offshore wind there are generally more projects available in a given year than are required by our deployment timeline. In this case we build a merit order of the available projects and select from the cheapest first to meet the projected deployment. For these technologies we assume that the strike price is determined as the strike price required by the most expensive project selected (i.e. the 'marginal strike price'). This is consistent with the objective of determining strike prices through competitive price discovery[128].

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126 The levelised cost of a project, and hence its required strike price, depends on its FID date, and so we calculate a series of required strike prices for each project – one for each potential FID tear.

127 For onshore and offshore wind we allow the strike price model a limited degree of flexibility to depart from the exact timeline deployment path. This is because the strike price model is seeking to build the least cost solution using discrete amounts of capacity. If the model was forced to build capacity in the exact manner as the timeline, unrealistic decisions would be made in the model, such as not building a 200MW project in a particular year because the timeline defines that there is only 150MW of capacity remaining to be deployed in that year. To avoid this, the model is given limited freedom over build in each year to represent more realistically the decisions developers undertake. In addition for onshore wind we have grouped projects for ease of modelling and this may also lead to a 'lumpier' deployment profile than in reality owing to large project sizes. Finally, our modelling does not allow project to commission capacity in phases across different years.

128 However the reality of how CfDs are allocated, at least in the early years, is likely to be more complex than this, and the CfD strike price available may be different from this.

In calculating strike prices for the purposes of this study, we consider all pipeline projects which have not yet reached financial commitment, although we recognise that in reality renewable projects commissioning before April 2017 may choose to receive support under the Renewables Obligation. Given our build time assumptions, this approach restricts the analysis for wind to projects coming on line from 2015 onwards for onshore wind and 2017 for offshore wind. We assume projects reaching FID before CfDs are formally available are able to procure projects through the FID enabling process.

For all technologies the exact strike price is calculated that would ensure a sufficient return on investment across the lifetime of the project, which for most technologies will be longer than the contracted CfD FiT period. For nuclear, biomass and CCS it is known approximately when projects will reach FID and this is presumed to be independent of other projects. For onshore and offshore wind, projects are given freedom to FID in any year after their first possible FID date. Projects are then built according to the ranking of their levelised cost, with limits on capacity deployed in each year forcing projects to FID in later years than the earliest possible year.

Difference between levelised cost and strike price received

There are a number of reasons why the CfD strike received by a project will not be the same as its levelised cost

First, the duration of CfD support may not be the same as the project operating life assumed in the levelised cost calculation. In our analysis we generally assume that, in making their investment decision, investors assume that a project earns electricity market revenues for the period between expiry of the CfD and the end of its operating life[129]. If revenues in this period are below the project's levelised cost (as is generally the case), then the required strike price must be higher to compensate.

Second, an adjustment may be required to offset any systematic difference between the market reference price in the CfD and the net electricity sales price realised by the generator (taking account of any 'route to market' costs):

- The levelised costs we have calculated are 'station gate' costs, but generators (or their off-takers) will incur the cost of transmission losses and Balancing Services Use of System charges (BSUoS) (typically around £2-3/MWh in total).
- In addition we assume that generators will on average achieve a lower electricity sales price than the CfD market reference price owing to the fact that it will not always be possible to sell the electricity in the trading periods which will determine the market reference price. For wind generators, the market reference price will be based on day-ahead trading but generators will generally have to rebalance within day or face imbalance charges. For baseload generators the market reference price is likely to be based on forward trading of year-ahead or season-ahead contracts – whilst generators can sell their electricity production forward will be set at these times it is possible they may need to rebalance in closer to delivery to take account of changes in availability.

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129 For our electricity price assumption we use a baseload wholesale electricity price consistent with DECC's 2012 Updated Energy and Emissions Projections (DECC (2012d)). However we assume that investors project a constant (in real terms) electricity price from five years beyond the FID date. This is consistent with the 'five year foresight' approach adopted by DECC in the Renewables Obligation Banding Review.

If a generator is selling its power under a long term power purchase agreement (PPA), for example for financing reasons, and the PPA off-taker is likely to charge a margin for providing this service and for taking on the volume risks described above. If a generator has its own trading capability there will still be a cost associated with managing these risks.

For wind we assume a 10% 'route to market' discount associated with managing within day trading risks (additional to the BSUoS and transmission losses adjustment referred to above). This is lower than discounts we currently observe in the market for long term wind PPAs, based on a perception that off-takers are pricing conservatively owing to genuine uncertainty about the costs of rebalancing wind positions within-day when there is a high degree of wind on the system[130]. For baseload generators we assume a 7% route-to-market discount based on baseload PPAs we have observed in the current off-take market. Clearly there is uncertainty in these assumptions, and this issue is a significant contributor to uncertainty in required strikes prices. (In Section 4.2 we investigate the sensitivity of offshore wind strike prices to this assumption).

Third, for onshore and offshore wind, we assume a single 'clearing' strike price is applicable for all projects that commission in a particular year, determined either by the Government's administrative price setting process or, later, through competitive auctions. This means that some projects are able to increase returns if they are significantly cheaper than the standard strike price for that year.

For nuclear, CCS, and biomass conversion projects, we assume each project receives a strike price required by that project, owing to smaller number of projects and/or range of different sub-technologies. For all technologies we report calculated strike prices in relation to a given commissioning year, consistent with DECC's approach for announcing strike prices.

Assessment of support levels

Knowledge of the strike prices required to achieve the deployment timeline for each technology then allows us to evaluate the level of support required in the form of CfD difference payments and the associated resource cost of this support (see Section 4.8).

4.2 Offshore wind

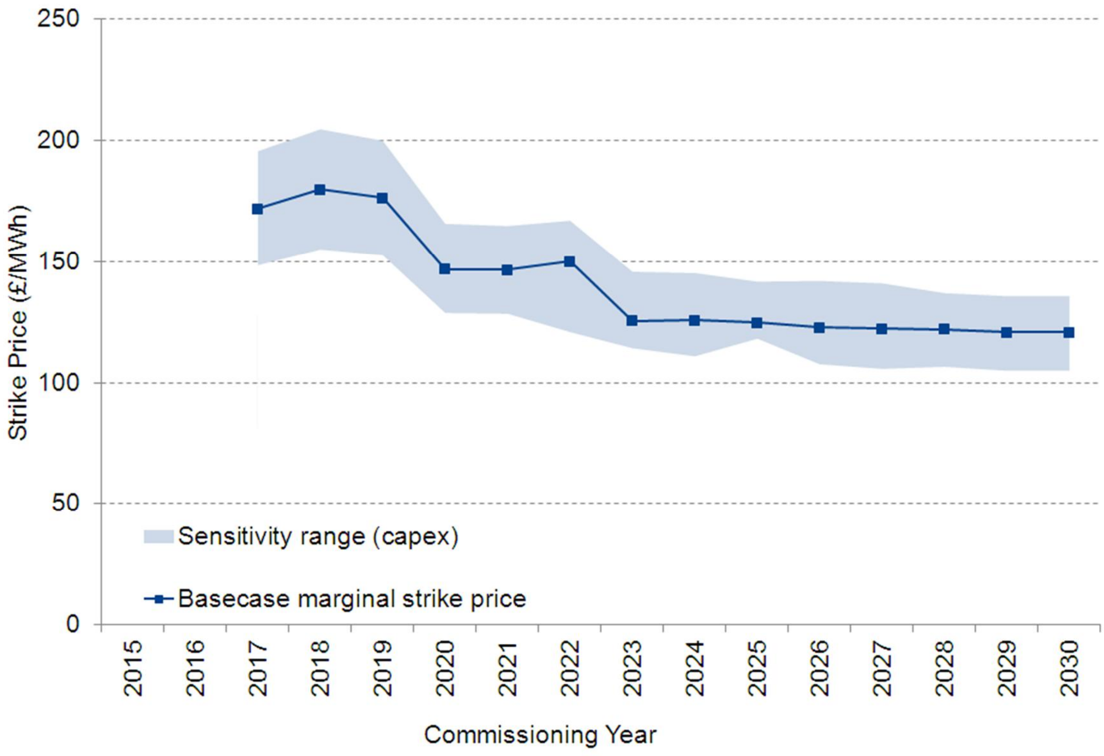
4.2.1 Lower deployment scenario

Figure 26 shows the strike prices we have derived for offshore wind in our lower deployment scenario. The central blue line is based on our central cost assumptions. Given the uncertainties involved in our cost and timeline assumptions, it is important to recognise that there is uncertainty in the derived strike prices. The pale blue range shows the range of strike prices corresponding to the largest variations observed in our sensitivity analysis (see below) – for offshore wind this corresponded to high and low capital cost assumptions. The strike price shown in any year is the strike price required

130 If it is windier on the day than was expected day-ahead, it is likely than many wind farms will be looking to sell additional output and so the within-day price will be lower than the day-ahead price. Conversely if it is less windy than was forecast, wind generators will be looking to buy additional electricity to cover their shortfall and so within-day prices are likely to be higher than day-ahead prices. Hence on average within-day rebalancing is likely to be at 'distress' prices compared to day-ahead prices. Our perception that off-takers may be pricing conservatively at present is based on initial results from a separate study we are currently conducting on this issue.

by the most expensive project which is selected to meet the timeline deployment in that year.

Figure 26 – Range of strike prices for offshore wind lower deployment scenario (£/MWh, 2012)



The strike prices shown for a given commissioning year represents the price awarded to projects which commissioning in that year.

Strike prices start in the range £150-200/MWh, but decrease over time as a result of capital and operating cost reduction and a decrease in the required rate of return for later projects as the technology matures. The step changes around 2020 and 2023 result from discrete changes in our assumptions for required rate of return (see Section 3.2) – in reality a smother profile might be expected[131]. The long term strike price is in the range £105-135/MWh.

As discussed in Section 4.1 above, the strike price required by a project is not the same as the levelised cost we have modelled in Chapter 3 for two reasons, as shown in Figure 27.

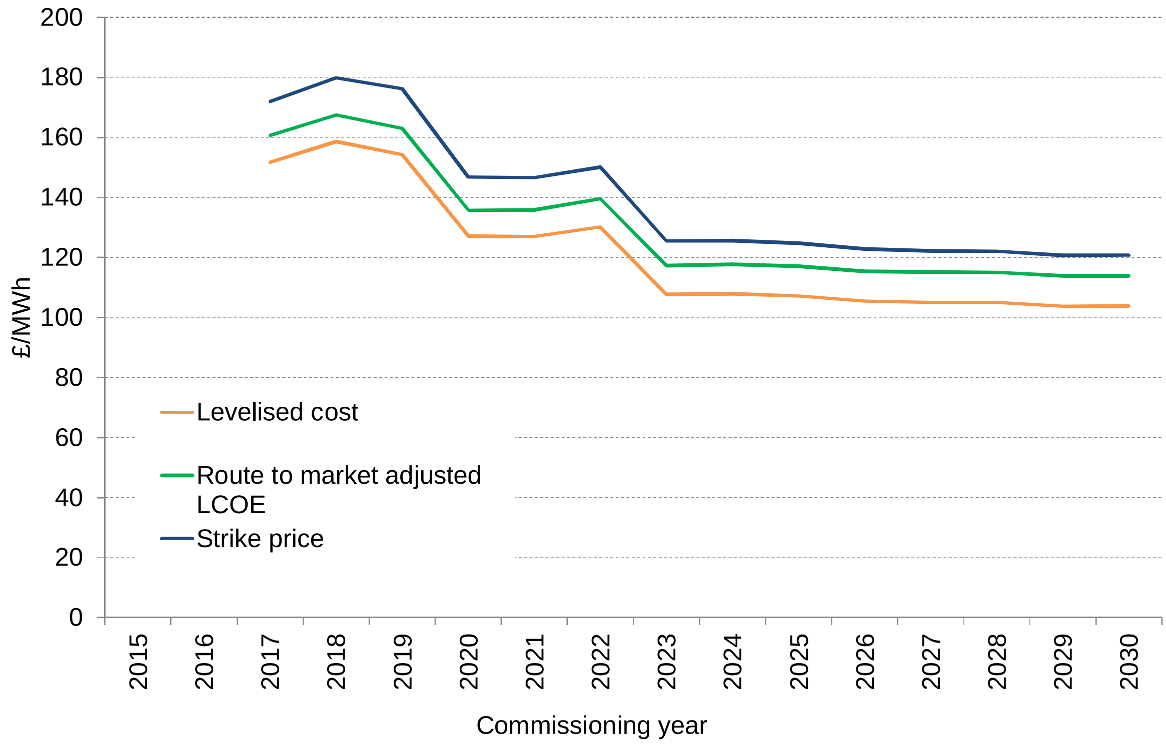
- First, our levelised costs are essentially the cost of generation at the station gate, and do not take into account the costs accessing a 'route to market'. For offshore wind we have assumed a 10% 'PPA discount' cost associated with managing within day trading risks, in addition to the cost of transmission losses and Balancing Services Use of System charges. Hence the uplift in strike prices required to compensate

131 Note also that the 'kink' in the lower end of the range in 2025 results from the strike price model selecting a different deployment pattern in this year compared to the central and high runs. This is a reflection of modelling limitations and should not be seen as significant.

offshore wind generators for the route to market cost is around £10/MWh (comparing the green and orange lines on Figure 27).

- The second uplift to the levelised cost reflects the expectation that CfD support will be for 15 years for offshore wind, but we have calculated levelised costs of a longer operating life (assumed to be 22 years). In the final seven years of this life the wind farm receives electricity market revenue only, so a higher strike price is required in the first 15 years to achieve the overall rate of return required by the investors. For offshore wind, this effect adds around another £7-12/MWh to strike prices (comparing the blue and green lines on Figure 27). This differential declines over time as our electricity price assumption rises over time.

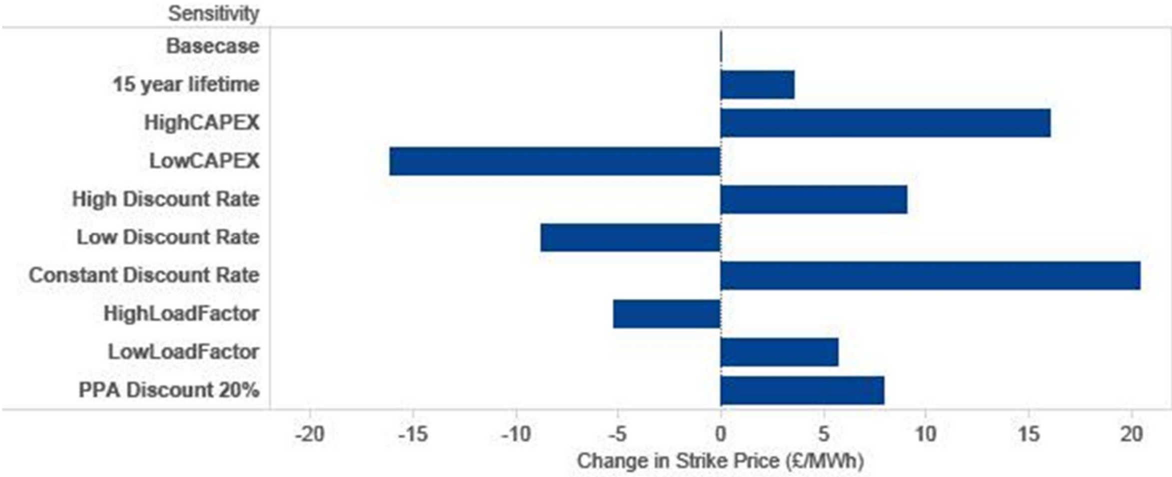
Figure 27 – Difference between strike price and levelised costs (central costs)



In Figure 28 we show the results of our sensitivity analysis for a selected offshore wind project, in order to give an indication of the range of uncertainty in modelled strike prices. For each of the key drivers of uncertainty we have selected a plausible high/low range based on a combination of ranges quoted in previous cost studies and our own judgement – see Annex A for a full list. We show the results of each sensitivity as the variation around the 'base case' strike price calculated using central assumptions.

For offshore wind capital cost is the main driver of uncertainty, with our assumed range of uncertainty leading to a range of around £30/MWh in required strike price. This illustrates the difficulty for policymakers in setting administered strike prices, and hence the need to move to strike price determination through a more competitive price discovery process as soon it is clear that there is a reasonable degree of competition for CfDs.

Figure 28 – Sensitivity analysis for offshore wind strike prices (lower deployment scenario)



The chart shows sensitivities in the required strike price for a Round 3 project reaching FID in 2020 and commissioning in 2023. The base case strike price in this example is £117/MWh.

The constant discount rate sensitivity is intended to illustrate the impact if the expected reduction in required rates of return does not materialise. It shows that around £20/MWh of the projected reduction in required strike price is based on the projected reduction in required return (from 12.4% today to 9.1% from 2020 onwards).

The '15 year lifetime' sensitivity illustrates the impact if investors do not take any account of electricity revenues beyond the 15-year CfD support period when making their investment decision. In this case, it increases the required strike price by around £4/MWh.

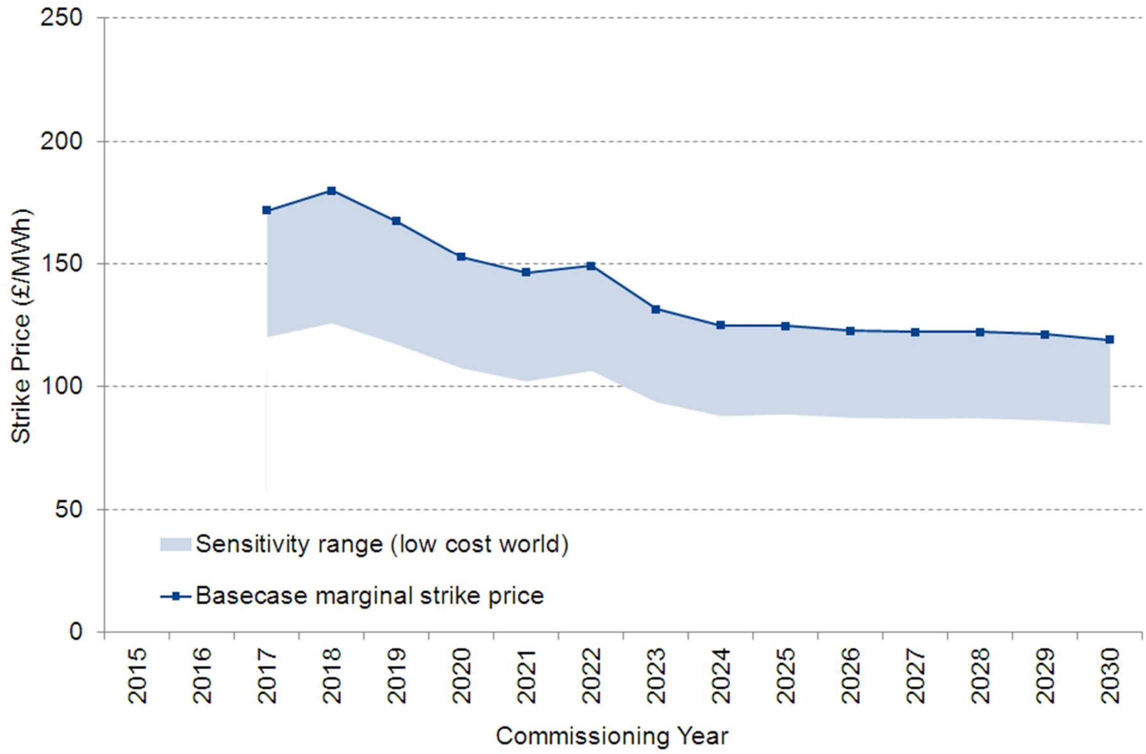
There is currently much uncertainty about what level of PPA discount reflects the real costs of managing within-day trading risk and imbalance risk. Our central assumption is 10%, but at present PPA providers typically quoting higher discounts for long term PPAs – closer to 20%. Increasing the discount to 20% results in an increase of around £8/MWh in strike prices.

4.2.2 Higher deployment scenario

Figure 29 shows the strike prices we have derived for offshore wind in our higher deployment scenario. This scenario assumes deployment of 40GW can be reached by 2030 (compared to 25GW in the lower deployment scenario). We believe this is plausible only if the costs of offshore wind decrease significantly – otherwise the support cost will become prohibitive. Hence the lower end of the range shown reflects a 'low cost' world in which capital cost, operating cost, and discount rate are all at the low end of our assumed range of uncertainty, and load factor is at the high end.

Comparing to Figure 26, the general level and trend of 'base case' strike prices follow a similar pattern even though significantly more capacity is being deployed (40GW versus 25GW). This reflects the fact that the supply curve for offshore wind is relatively flat – there are many competing projects available with broadly similar costs. However in the 'low cost world', required strike prices fall to below £90/MWh for projects commission by the mid-2020s.

Figure 29 – Range of strike prices for offshore wind higher deployment scenario (£/MWh, 2012)



The strike prices shown for a given commissioning year represents the price awarded to projects which commissioning in that year.

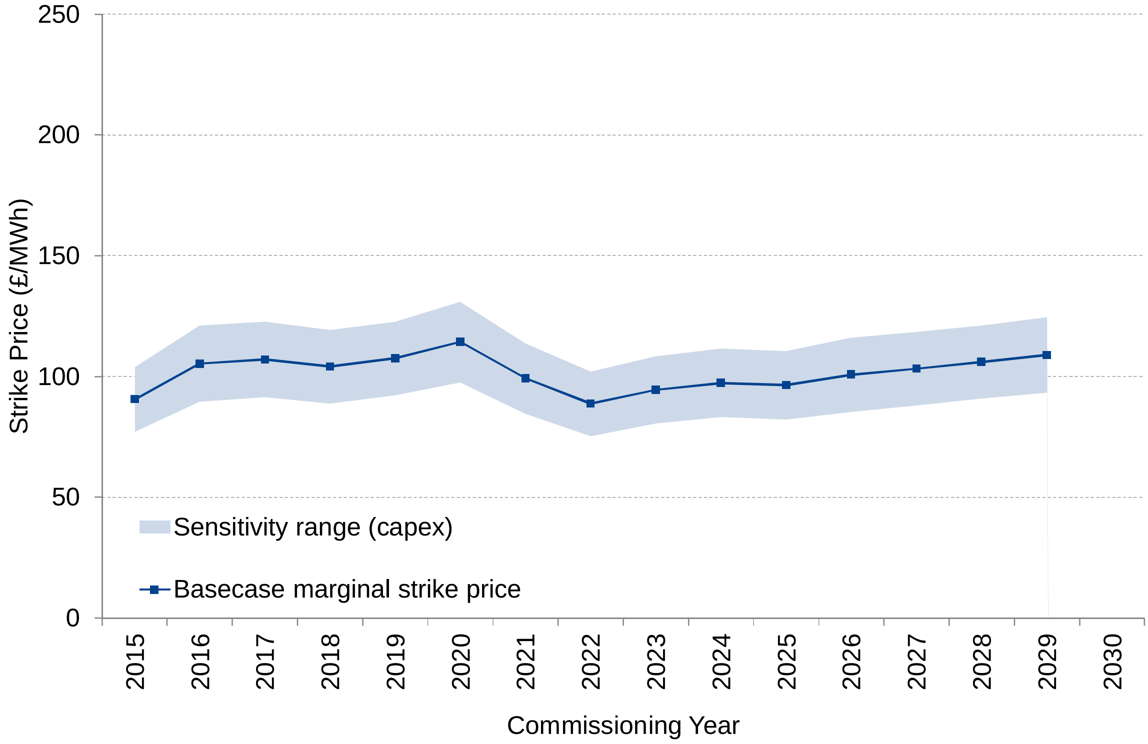
4.3 Onshore wind

Figure 30 shows the strike prices we have derived for our onshore wind deployment timeline (which deploys around 25GW by 2030). The central blue line is based on our 'base case' cost estimations. In developing the costs of onshore wind deployment several cost uncertainties were identified, the impact of which can be evaluated through sensitivity analysis. The shaded light blue area of Figure 30 shows the range of strike prices based on high and low capital cost scenarios. Clearly, reducing or increasing capital costs for onshore wind projects would have a significant impact on the strike price required and such changes constitute the largest diversion from our 'base case' cost assumptions for onshore wind.

The strike prices set out in Figure 30 are those which, according to our modelling, are required to incentivise onshore wind deployment to be in line with the timeline set out in Section 2.3.3. The strike prices shown are the marginal strike prices for projects commissioning in a particular year. The exact profile from year to year is to some extent a reflection of our model, which considers strike prices needed in a given year based on the costs of projects available in that year, and hence the strike price for a given year may not reflect the cost of the majority of the projects deployed in that year. Given the uncertainties involved in the analysis it is not possible to draw firm conclusions about strike prices for individual years, but we believe that the derived strike prices are on average representative of those which would be required given our cost distributions and timeline assumptions. In reality the Government is likely to set a smoother profile of strike prices based on an assessment over a number of years. Hence we do not believe it

is plausible that strike prices will rise in the short and medium term and it is more appropriate to average our derived values over the first few years[132].

Figure 30 – Range of strike prices for onshore wind (£/MWh, 2012)



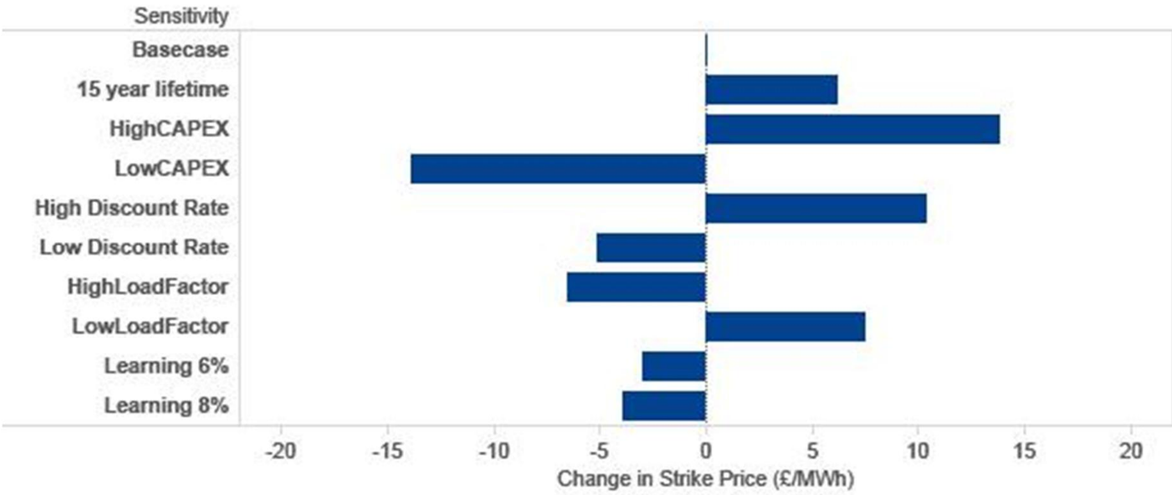
The strike prices shown for a given commissioning year represents the price awarded to projects which commissioning in that year.

However, although there is some uncertainty in the shape of the near-term curve in Figure 30, there is some logic behind the longer term trends. Our analysis shows strike prices falling in 2020-2022 as new projects that submit to a planning authority between 2013 and 2020 become available for deployment. Strike prices then rise again in the late 2020s as the cheaper projects are deployed first. In reality, there is much more uncertainty than our modelling suggests about the emergence of new projects and their cost characteristics, but the idea that strike prices might rise in the longer term as the best sites are deployed is plausible. Note however that learning effects could offset this (see below).

As for offshore wind, modelled strike prices are higher than the levelised costs derived in Chapter 3 owing to route to market costs described in Section 4.2.1 as well as the mismatch between CfD period and assumed operating lifetime.

132 It should also be remembered that projects commissioning before April 2017 may choose to receive support under the Renewables Obligation rather than through CfD FiTs.

Figure 31 – Sensitivity analysis for onshore wind strike prices



The chart shows sensitivities in the required strike price for an onshore wind project reaching FID in 2020 and commissioning in 2022. The base case strike price in this example is £98/MWh

Figure 31 shows the results of our sensitivity analysis for a representative project group (see explanation of the grouping of projects in Section 3.3.3). For each of the key drivers of cost uncertainty a high/low range has been allocated in line with ranges quoted in previous cost studies and our own judgement – see Annex A for a full list. Figure 31 shows the results of each sensitivity relative to the 'base case' strike price required, calculated using our central cost assumptions.

Uncertainty over a project's capital expenditure represents the most significant variation from the 'base case' strike price, leading to a range of around £30/MWh around the 'base case'. Such a range is significant and highlights the need for a competitive aspect to strike price determination as it will be hard to determine the required strike price through the administrative price-setting process.

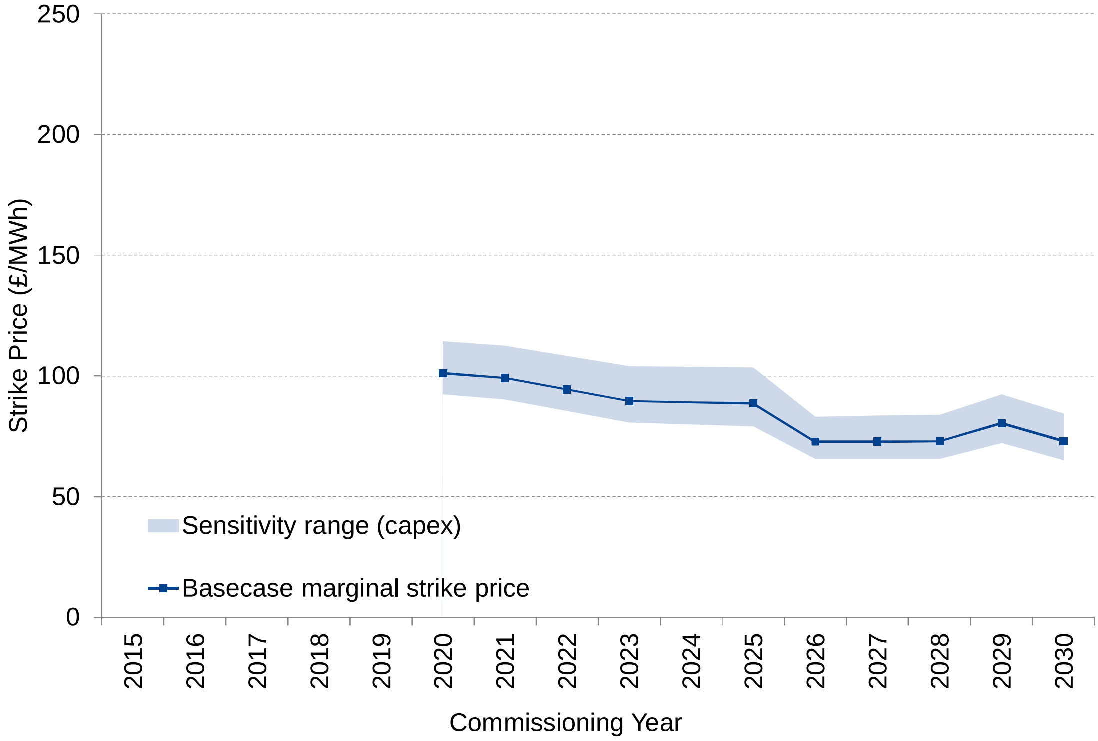
The '15 year lifetime' sensitivity illustrates the strike price investors would require if they were to discount (to zero) electricity revenues beyond the 15-year CfD support period when making an investment decision. This increases the strike price by around £6/MWh.

Capital cost learning was not considered within the onshore wind 'base case' (see Section 3.3.1). Learning rates on capital expenditure were considered as a sensitivity based on learning rate assumptions of 6% and 8%. As Figure 31 shows, such learning reduces the strike price by £3/MWh and £4/MWh respectively – these are smaller changes then those implied by uncertainty in discount rates or load factors.

4.4 Nuclear

Figure 32 shows the strike prices we have derived for our nuclear deployment scenario. The central blue line is based on our central cost assumptions. Given the uncertainties involved in our cost and timeline assumptions, it is important to recognise that there is a high degree of uncertainty in the derived strike prices. The pale blue range shows the range of strike prices corresponding to high and low capital cost assumptions, which along with discount rate, is the sensitivity that delivers the biggest variance to strike prices. However the true range, combining all the uncertainties involved, could be wider than this.

Figure 32 – Range of strike prices for nuclear scenario (£/MWh, 2012)



The strike prices shown for a given commissioning year represents the price awarded to projects which commissioning in that year.

Based on our analysis, strike prices for nuclear start in the range £90-115MWh. Note that these are derived from the assumptions outlined in Chapter 3 and given the uncertainties involved the actual range of possible outcomes is likely to be wider than our derived range[133].

Modelled strike prices decrease over time as a result of capital cost reduction and experience leading to a de-risking of nuclear projects that require a lower rate of return on capital as we move through the project pipeline. The long term strike price is in the range £65-75/MWh (although this reduction will be dependent on successful implementation of the earlier projects).

It is worth noting that out project pipeline deploys two separate nuclear reactor technologies with different cost profiles and cost reduction trajectories that are dependent on the number of projects commissioning and the timetable for doing so. This explains the slight rise in strike prices visible in Figure 32 that is caused by the construction of an ABWR at FOAK cost levels at a stage when PWR has already benefited from most of its assumed reductions in cost. In reality we believe different strike price levels may be set for different reactor types – Figure 33 shows our assessment of strike prices by reactor type. Given the discrete nature of the nuclear pipeline, we assume that each project effectively receives the individual strike price which it requires rather than the marginal strike price for projects commissioning in a given year.

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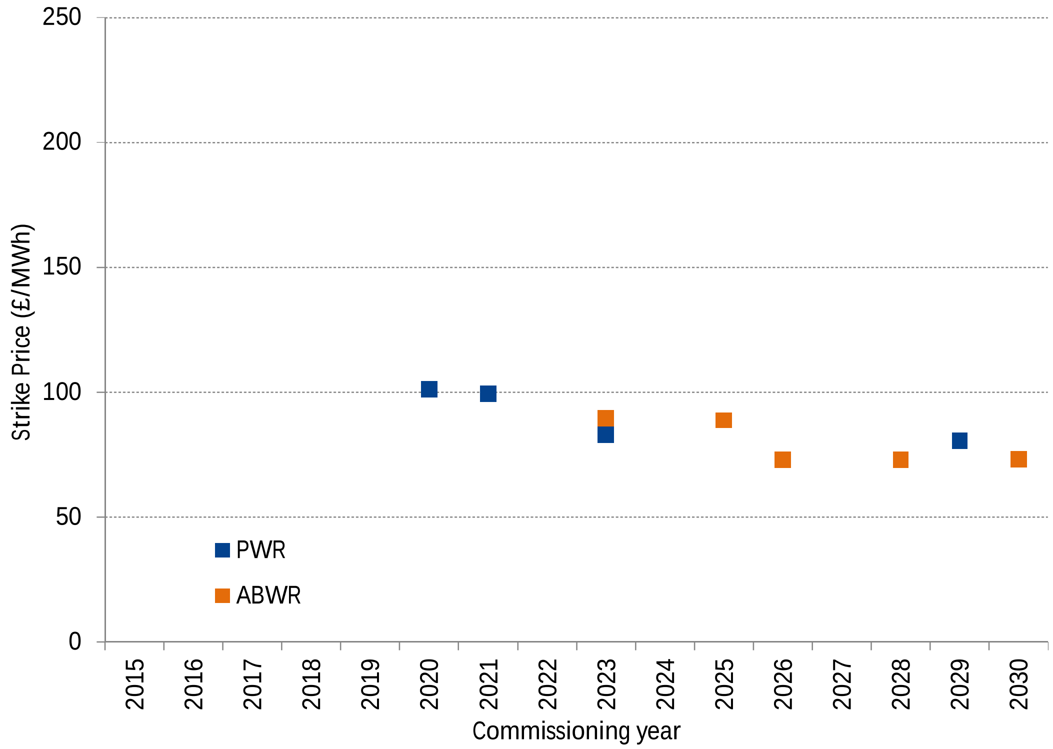
133 It is also worth noting that our cost estimates do not address the Hinkley Point site specifically and in performing this study we have had no knowledge of anything relating to current discussions between EDF and the Government in relation to a CfD for Hinkley Point.

Figure 33 – Strike prices for nuclear differentiated by reactor type (£/MWh, 2012)



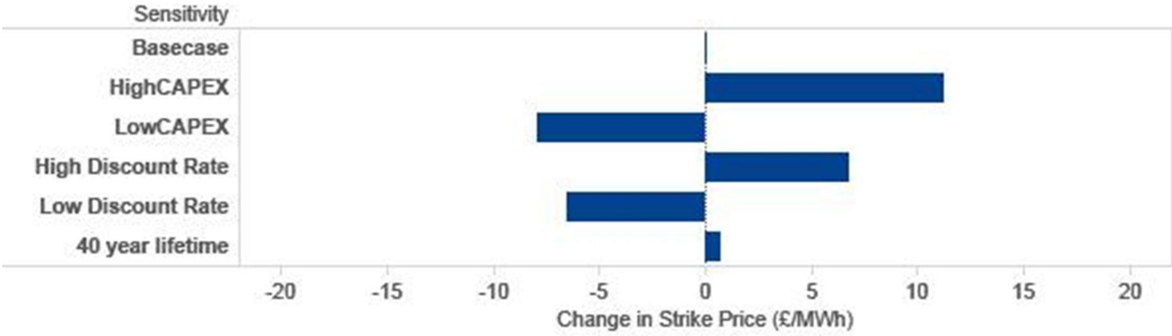
Notes
1) The strike prices shown for a given commissioning year represents the price awarded to projects which commission in that year.
2) Based on our central cost assumptions only

Another key point on nuclear strike price calculations is that the CfD is assumed to apply over a 40 year lifetime compared to a 15 year CfD for all other technologies. The CfD duration for nuclear is not known at the time of writing, although press speculation suggests that it will be around 35-40 years.

Compared to wind, the difference between levelised cost and required strike price is much lower for nuclear. First, we assume a lower 'route to market' discount of 7% since nuclear is more predictable than wind and so has lower volume risk for off-takers. Second, the 40-year CfD lifetime means that revenues beyond this period are discounted so heavily that they have negligible effect on investment decisions[134].

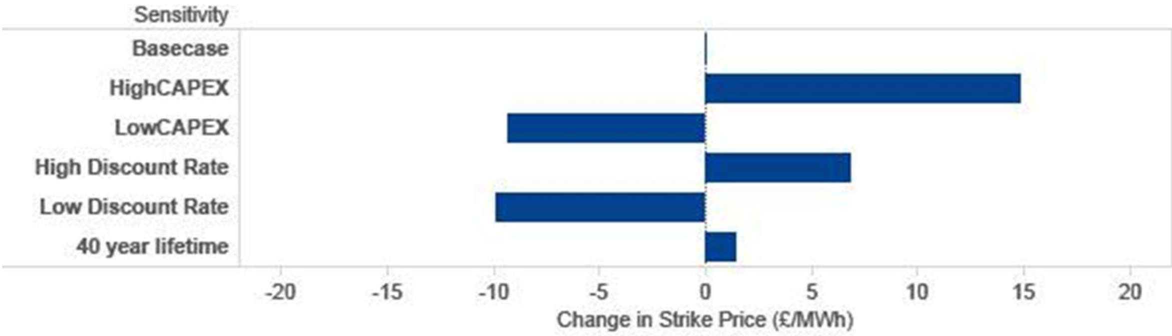
[134] In addition, nuclear costs are much closer to market electricity prices than offshore wind.

Figure 34 – Sensitivity analysis for PWR prices



The chart shows sensitivities in the required strike price for a NOAK PWR project reaching FID in 2020 and commissioning in 2025. The base case strike price in this example is £83/MWh.

Figure 35 – Sensitivity analysis for ABWR prices



The chart shows sensitivities in the required strike price for a FOAK ABWR project reaching FID in 2020 and commissioning in 2025. The base case strike price in this example is £89/MWh.

In Figure 34 and Figure 35 we show the results of our sensitivity analysis for a selected PWR and ABWR project respectively, in order to give an indication of the range of uncertainty in modelled strike prices. For each of the key drivers of uncertainty we have selected a plausible high/low range based on a combination of ranges quoted in previous cost studies and our own judgement – see Annex A for a full list. We show the sensitivity results as the variation around the ‘base case’ strike price calculated using central assumptions.

For nuclear, capital cost and discount rate are the two main drivers of uncertainty, with our assumed range of uncertainty leading to an average range of around £20/MWh in required strike price for each. This illustrates the difficulty for policymakers in setting administered strike prices and highlights the need, particularly with nuclear to negotiate the strike price on a project by project basis.

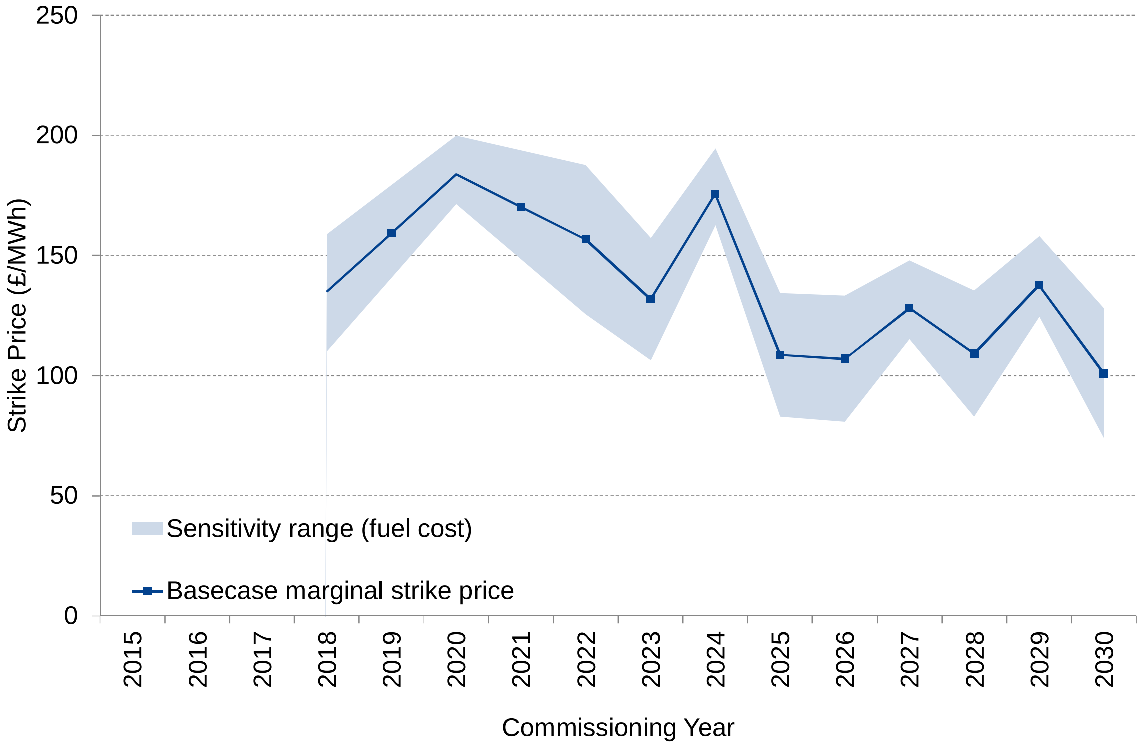
The ’40 year lifetime’ sensitivity illustrates the impact if investors do not take any account of electricity revenues beyond the 40-year CfD support period when making their investment decision. In this case, it increases the required strike price by a modest £1-2/MWh. This sensitivity shows a small impact on strike prices due to the highly discounted benefit of electricity revenues in the final 20 years of a nuclear plant operating to a 60 year lifetime.

4.5 CCS

Figure 36 shows the strike prices we have derived for our CCS deployment scenario. The central blue line is based on our central cost assumptions. Given the uncertainties involved in our cost and timeline assumptions, it is important to recognise that there is uncertainty in the derived strike prices. The pale blue range shows the range of strike prices corresponding to high and low fuel cost assumptions – it is this sensitivity that delivers the biggest variance to strike prices.

The strike prices shown in the chart are extremely 'turbulent' due to the fact that there are five different capture technologies to choose from each with quite different cost profiles. Our project timeline assumes that a variety of capture technologies are supported through the two pre-commercial phases of deployment, and this decision in particular results in strike price volatility. The later commissioning years show less variance in strike price primarily due to the fact that we have elected to predominately deploy one capture technology – gas-post combustion CCS.

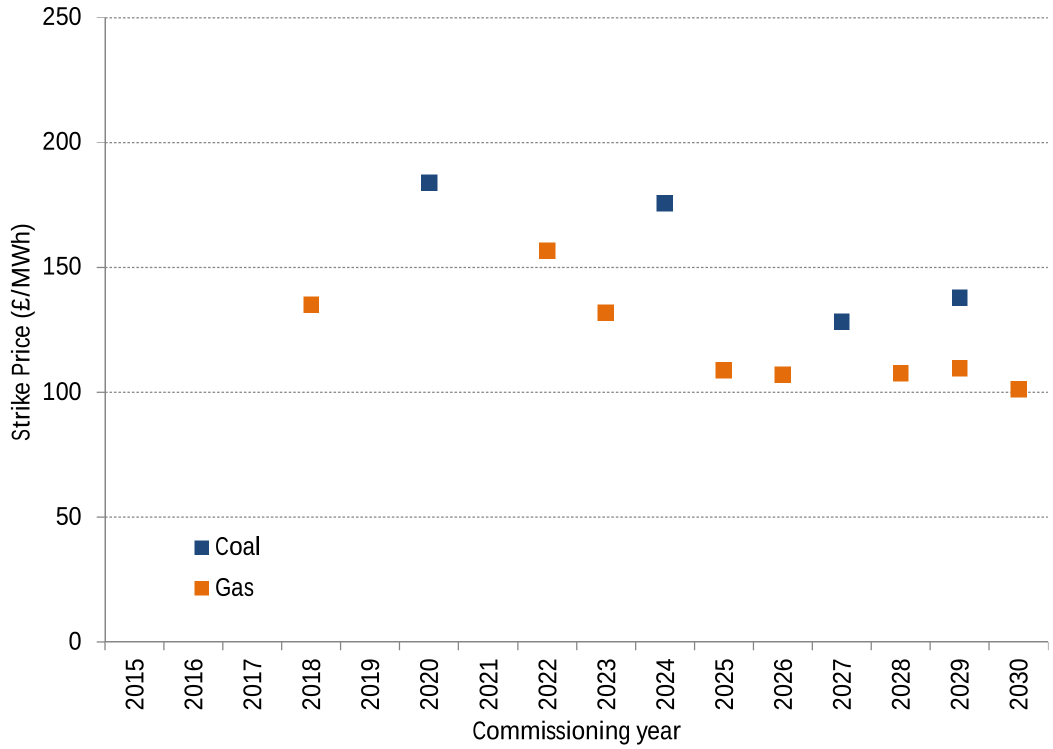
Figure 36 – Range of strike prices for CCS scenario (£/MWh, 2012)



The strike prices shown for a given commissioning year represents the price awarded to projects which commissioning in that year.

The two jumps up in strike price in 2027 and 2029 show the commissioning of two commercial coal plants which are both on a higher cost profile. In reality different strike prices might be set for different capture technologies. Figure 39 assumes strike prices are differentiated by fuel type, but it is possible they might be further differentiated by capture technology.

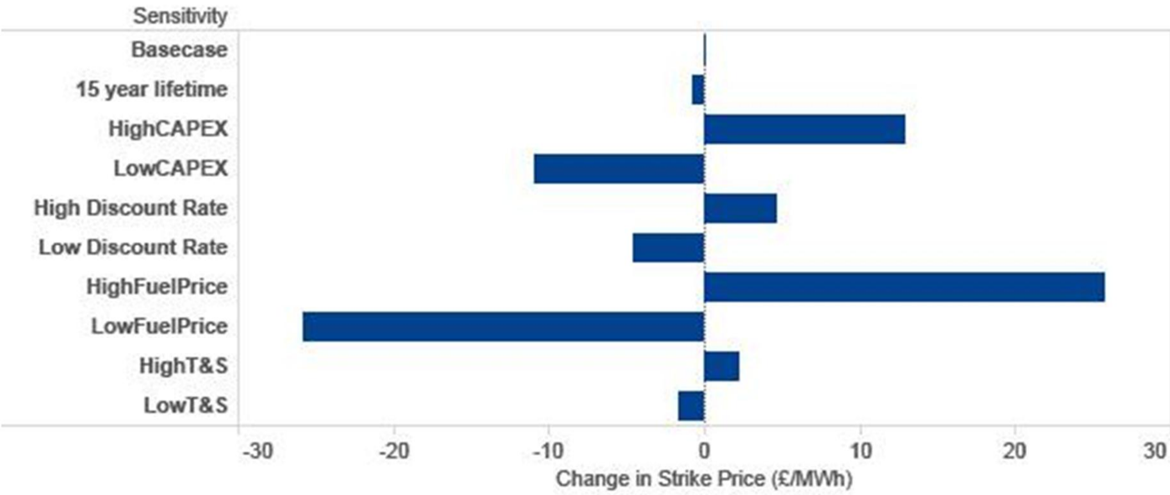
Figure 37 – Strike prices CCS differentiated by fuel type (£/MWh, 2012)



Notes
1) The strike prices shown for a given commissioning year represents the price awarded to projects which commission in that year.
2) Based on our central cost assumptions only
3) Gas CCS includes both pre and post-combustion capture projects. Coal CCS includes both oxyfuel and post-combustion capture projects

Strike prices for pre-commercial coal CCS start in the range £150-190/MWh with gas starting in the lower range of £130-140/MWh. Both ranges decrease over time as a result of learning benefits leading to a reduction in the capital cost of capture plants and lower discount rate requirements assumed for each new project of a specific capture plant technology. Due to the small number of discrete projects in our pipeline we have not been able to clearly show the cost reduction potential for all capture technologies but have elected to instead focus on one technology, gas post-combustion CCS, as it has the lowest cost profile based on our cost assumptions. The long term strike price for this technology is in the range £100-110/MWh. Expensive oxy-fuel and IGCC plants (commissioning in 2027 and 2029) requires a higher strike price of around £130-140/MWh.

Figure 38 – Sensitivity analysis for CCS prices



The chart shows sensitivities in the required strike price for a gas post-combustion CCS project reaching FID in 2021 and commissioning in 2025. The base case strike price in this example is £109/MWh. High and low fuel prices re taken from the high and low cases in the 2012 Updated Energy and Emissions Projections (DECC (2012d)).

The CCS strike price is very sensitive to fuel prices showing that investors' perception of future fuel price is very important when considering strike price negotiation. Figure 38 shows that the range of fuel price assumptions delivers a sensitivity range of £50/MWh. The Government has proposed linking CfD strike prices to fuel prices to remove the risk of support payments diverging from underlying fuel costs once a project is operational. The large sensitivity to fuel prices also illustrates the uncertainty around whether coal or gas CCS will be the cheaper technology in the long term and hence the value of keeping both options open.

The other key sensitivity is the capital cost estimates which show a range of £25/MWh for gas post combustion. It is important to note that the level of uncertainty shown on both fuel prices and capital cost has the potential to change which capture technology is most attractive to investors.

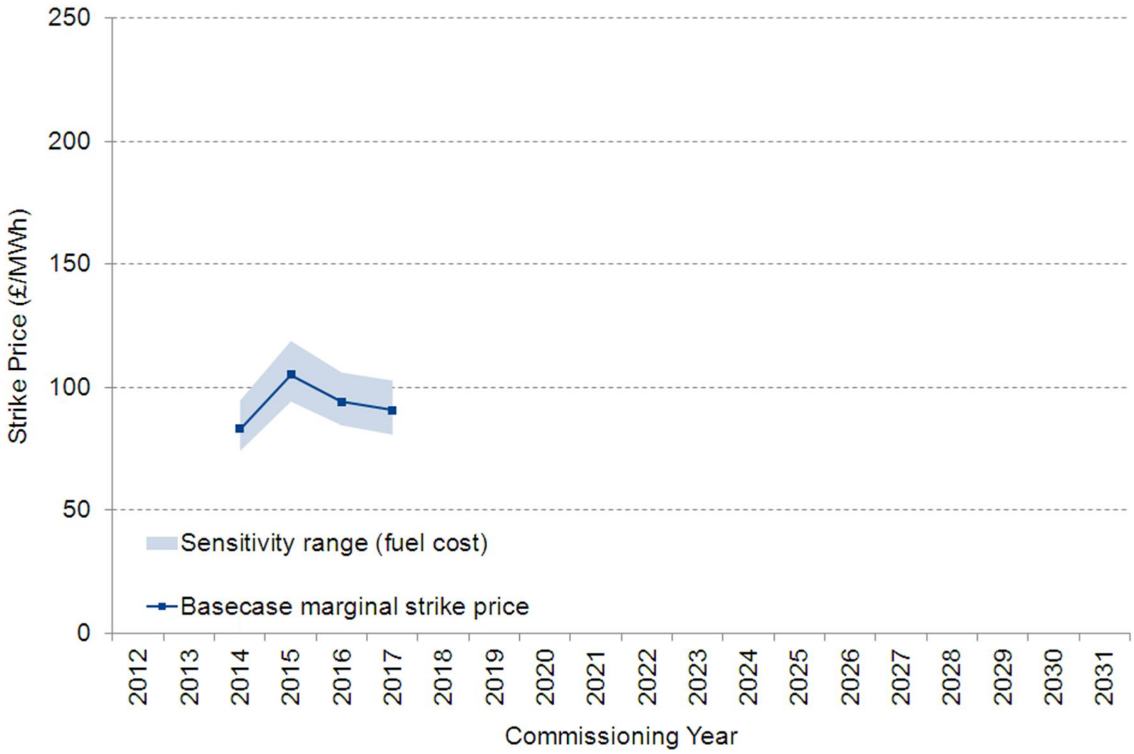
The T&S cost sensitivities are based on a range of £7.9-16.9/tCO_2. It is possible that in reality costs are outside this range – particularly for early projects where T&S costs may be more expensive.

4.6 Biomass conversions

Our projected strike prices for biomass conversions, shown in Figure 39, are generally in the range £80-105/MWh. Where more than one project commissions in the same year, the chart shows strike prices for the most expensive.

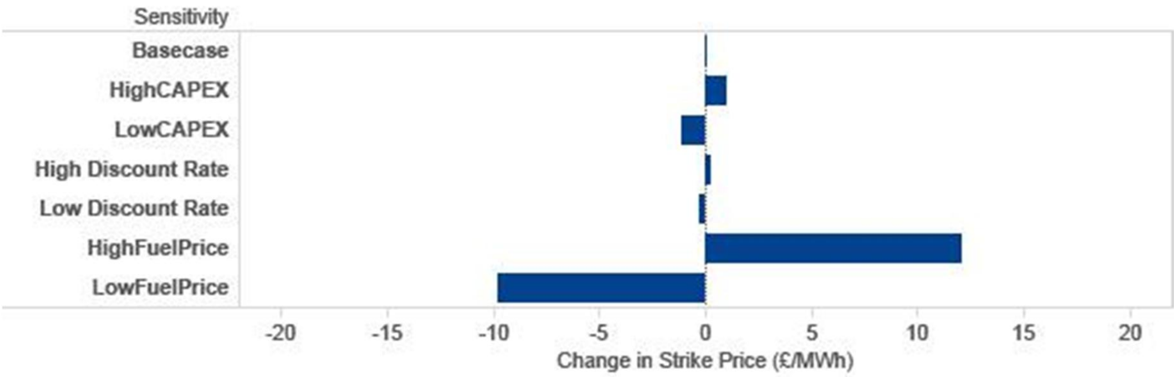
The high values in 2015 derive from the fact that one of the projects which our timeline assumes is deployed in that year has relatively high costs owing to its relatively small size. Given that we believe there could be competition for biomass conversion CfDs, it is possible that in reality a lower strike price would still be able to bring forward the same level of capacity.

Figure 39 – Range of strike prices for biomass conversions (£/MWh, 2012)



The strike prices shown for a given commissioning year represents the price awarded to projects which commissioning in that year.

Figure 40 – Sensitivity analysis for biomass conversion strike prices



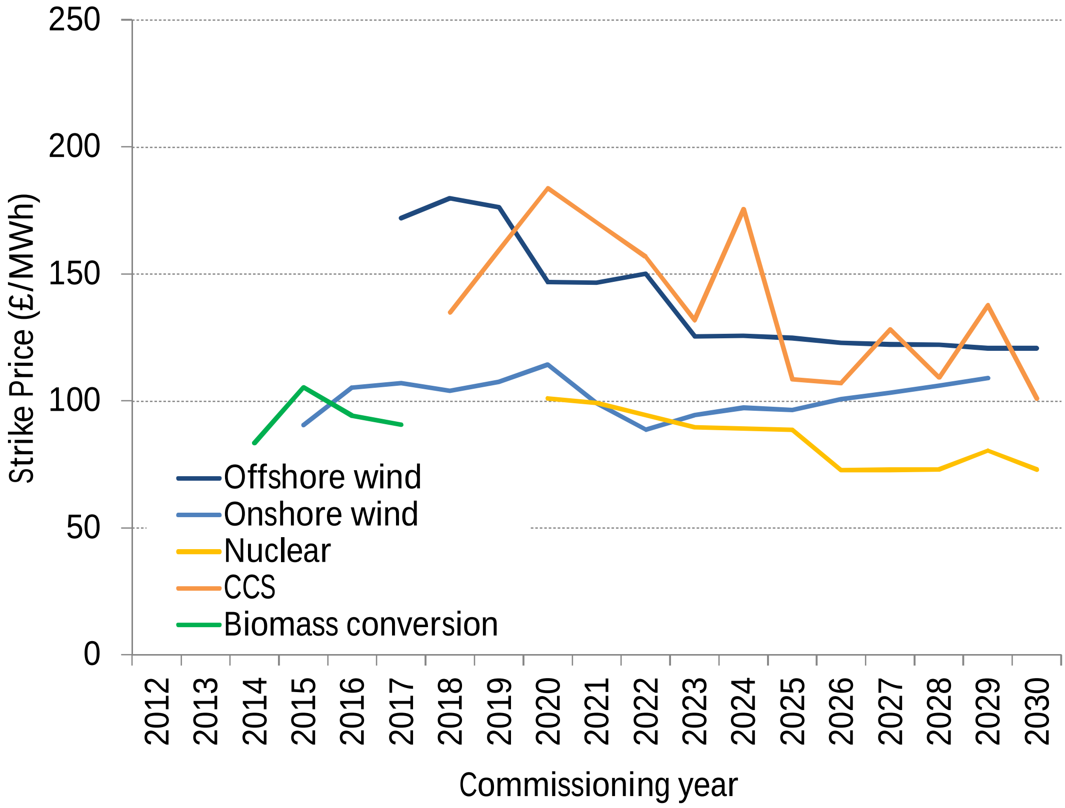
The chart shows sensitivities in the required strike price for a biomass conversion project reaching FID in 2014 and commissioning in 2016. The base case strike price in this example is £91/MWh.

In Figure 39, the sensitivity case we have used to illustrate the range of potential strike prices is fuel cost, as this is by the far the biggest driver of uncertainty – see Figure 40. Our fuel price uncertainty range of around ±£1/GJ leads to an uncertainty in required strike price of around ±£10/MWh (although other input uncertainties mean that the overall uncertainty in strike prices could be more than this). This is because fuel cost is the dominant component of the levelised cost of generation from a biomass conversion project. Compared to this, uncertainties associated with capital cost and required rate of return are relatively minor.

4.7 Summary

Figure 41 compares the strike prices we have derived across the different technologies. For clarity we show only the central values of the ranges we have derived, but it should be remembered that there is a range of uncertainty around these.

Figure 41 – Summary of calculated strike prices (central values) (£/MWh, 2012)



The strike prices shown for a given commissioning year represents the price awarded to the most expensive projects which commissioning in that year. The chart shows only the central value of the range of strike prices we have calculated.

The chart illustrates that, as might be expected from the cost distribution derived in Chapter 3, the technologies requiring the highest strike prices are offshore wind and CCS, whilst onshore wind, nuclear, and biomass conversion require lower strike prices. According to our analysis, in the long term nuclear projects require the lowest strike prices.

In interpreting these results the reader should bear in mind a number of limitations to the analysis:

- The large number of technologies and of individual projects we have modelled limits the level of detail we have been able to employ in cost assumptions.
- In any case there is inherent uncertainty in many of our assumptions because we are projecting what might happen in the future. The message from the sensitivity analyses presented in previous sections of this chapter is that uncertainty in project costs leads to significant uncertainty in relation to the required strike price.
- Our strike prices have been derived assuming projects are deployed to meet our projected deployment timelines. For onshore and offshore wind the strike prices

shown above are based on the marginal project selected by our model. In fact projects may not come forward as projected, and the marginal project may have a different cost profile.

4.8 Assessment of CfD support and resource costs

4.8.1 Methodology

In this section we examine the implications of the strike prices we have derived for the total level of CfD payments which will be made to CfD FiT generators – we define this as the 'support cost'. We calculate these based on differences between the strike price and the annual average market electricity price, multiplied by the volume of electricity generated by each project deployed under our deployment timelines.

These support costs represent the CfD FiT payments to be made to low-carbon generators, based on electricity market prices consistent with the deployment of those generators. However if the low-carbon generators were not deployed then wholesale electricity prices are likely to be different. If we assume the likely default alternative (i.e. the 'counterfactual') is gas-fired CCGTs, then in the absence of low-carbon generation electricity prices are likely to be determined by the long run marginal cost of gas CCGTs. Hence it can be argued that the net incremental cost (the 'resource cost') of this low-carbon generation is the difference between the strike prices they require and the long-run marginal cost of gas CCGT generation. This resource cost represents the net financial impact on consumers, taking account of both the subsidy required to deploy low-carbon generation and the benefit of the resulting lower wholesale electricity prices.

For wholesale market electricity prices we use annual baseload prices consistent with DECC's Updated Energy Projections 2012[135] to calculate support costs. For nuclear, CCS, and biomass conversion, this represents a good proxy to the CfD market reference price which is likely to be adopted for these technologies – a baseload price. For wind, for which the market reference price is likely to be a day-ahead hourly price, using annual prices to calculate difference payments ignores the fact that wind farms are on average likely to generate more electricity when the hourly price is lower than the annual average – the 'wind cannibalisation' effect. Hence our approach is likely to slightly underestimate the support payments required for wind projects. (A more detailed analysis is beyond the scope of this study.) To calculate resource costs we use a wholesale electricity price projection supplied by the Committee, based on the long-run marginal cost of gas CCGT generation.

For wind we assume that the strike price awarded to an individual project is the 'marginal' strike price – i.e. the strike price required to bring on the most expensive project required to meet the timeline deployment in a given year. This simulates the impact of a competitive auction process for CfD allocation. For nuclear and CCS we assume each project receives the individual strike price required by that project, owing to the much smaller number of discrete projects. Even if two projects are available to be deployed in a given year, it may be appropriate to have different administered strike prices – for example for different nuclear reactor types or different CCS capture technologies. For biomass conversion we also assume each project is awarded an individual strike price rather than a marginal strike price, even though there may be scope for a more competitive allocation process. However, as most biomass conversion projects have

[135] DECC (2012d)

similar required strike prices this is unlikely to have a significant impact on the overall support cost for biomass conversion.

4.8.2 Projected support and resource costs

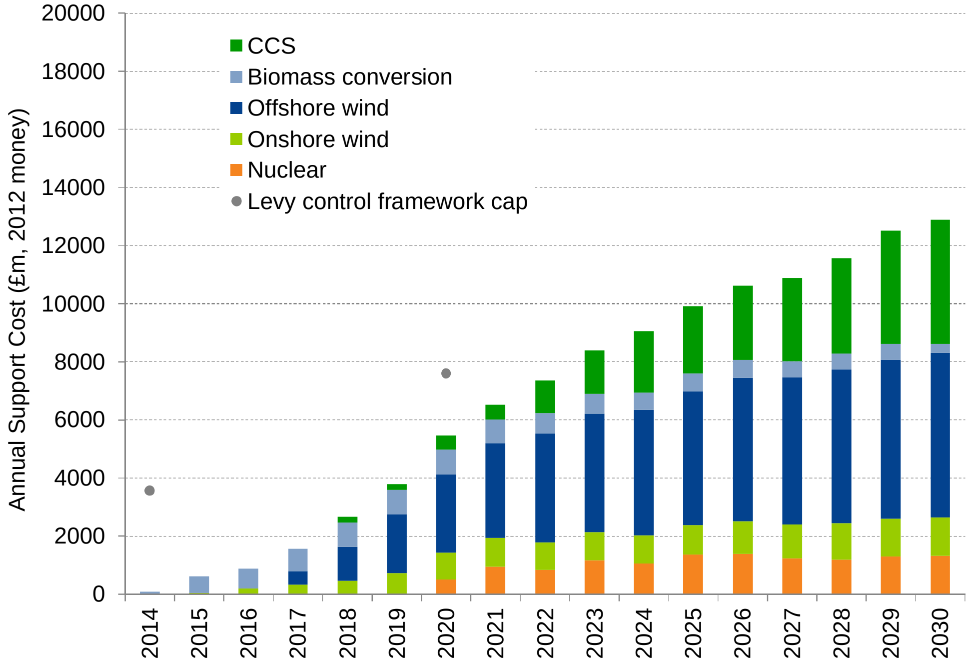
Figure 42 shows the total support costs we have derived for the low-carbon generation deployed in our timelines, based on our central cost assumptions and lower offshore wind deployment scenario, whilst Figure 43 shows projected resource costs. The latter are assessed against an assumption for the long-run marginal cost of gas CCGT generation supplied by the Committee.

Total support costs increase over time with the growth in deployment. Support costs are around £5.5bn in 2020 and £13bn in 2030. The projected resource costs are lower than the projected support costs in Figure 42 because they take account of the fact that deployment of low-carbon generation is expected to lead to lower wholesale electricity prices than would otherwise be the case.

Figure 44 shows the evolution of support costs per MWh of low-carbon generation contributed by each technology. Support cost per MWh falls over time because projected electricity prices rise over time.

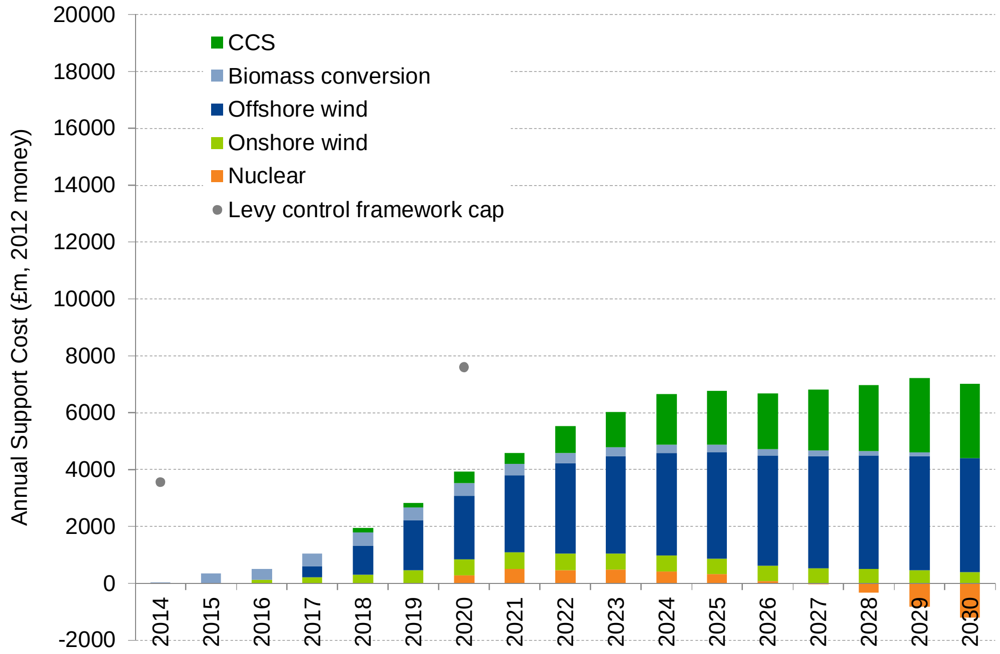
Offshore wind is the biggest contributor to total support costs, both in aggregate terms and per MWh. Support costs for offshore wind amount to around £2bn in 2020 and around £6bn in 2030. This is followed by CCS, which also requires significant support, although this becomes significant only in the 2020s. Support for onshore wind, nuclear, and biomass conversion remains at more modest levels since these technologies have required strike prices much closer to projected market electricity prices. Indeed for nuclear only the earlier projects need any significant support.

Figure 42 – Projected CfD FiT support costs (base case cost assumptions, lower offshore wind deployment scenario) (£m 2012)



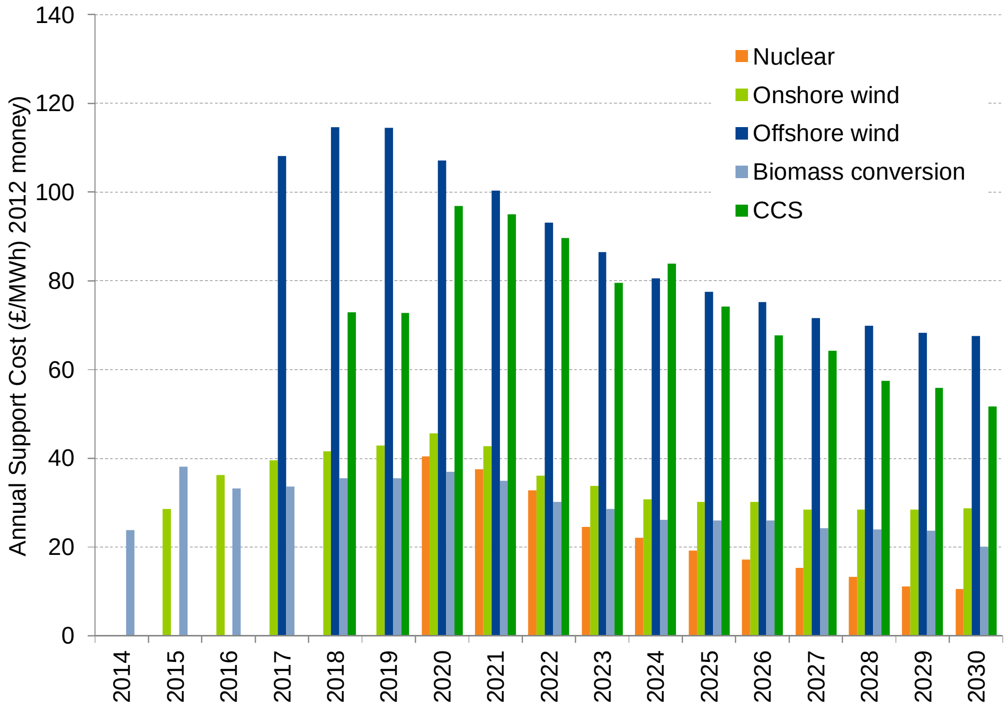
Note that the Levy Control framework caps refer to financial years 2014/15 and 2020/21, whereas support costs are shown on a calendar year basis. Support costs relate to CfD FiTs only and do not include support under the Renewables Obligation or small-scale Feed-in Tariff scheme.

Figure 43 – Projected CfD FiT resource costs (base case cost assumptions, lower offshore wind deployment scenario) (£m 2012)



Note that the Levy Control framework caps refer to financial years 2014/15 and 2020/21, whereas support costs are shown on a calendar year basis. Support costs relate to CfD FiTs only and do not include support under the Renewables Obligation or small-scale Feed-in Tariff scheme.

Figure 44 – Support costs per MWh (base case cost assumptions, lower offshore wind deployment scenario) (£/MWh 2012)



Annual support cost per MWh is calculated as total support cost for a given technology in a given year, divided by the volume of electricity delivered in that year. Support costs relate to CfD FiTs only and do not include support under the Renewables Obligation or small-scale Feed-in Tariff scheme.

Figure 42 and Figure 43 also show the approximate level of the Levy Control Framework cap in 2014/2015 and 2020/2021– these are £3.6bn and £7.6bn respectively. These values represent the allowed budget for support under the Renewables Obligation, CfD FiTs, and small scale feed-in tariffs[136].

It is beyond the scope of this study to assess support costs of the Renewables Obligation and small scale FiTs. However one can assume that the £3.6bn in 2014/15 is accounted for almost exclusively by ROC and small-scale FiT schemes since very few projects funded under CfD FiTs will be online by then. For these support schemes (i.e. ROCs and small-scale FiTs), the support per MWh for an individual generator is the same each year (in real terms) throughout the support life of 20 years. The vast majority of these projects will still be generating in 2020 and so the RO and small-scale FiT payments are likely to be at least £3.6bn, even before allowing for projects currently under construction which will register for ROCs rather than CfD FiTs[137]. In addition there could be further growth in small scale FiT payments. Hence, according to this logic, at least £3.6bn will be required for RO and small scale FiT generators in 2020/21, leaving £4bn for CfD FiT payments.

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136 If support costs exceed these limits by more than 20%, DECC must implement policies to reduce support costs. HMT (2011)

137 In this study we have generally assumed that uncommitted renewables projects will register for CfD FiTs rather than ROCs, and Figure 42 reflects this. This is not to say that this will be the reality, but the objective of this study has been to model strike prices and so we have done this for all projects which could be eligible for a CfD. However there are some projects currently under construction – e.g. Humber Gateway – which we have not included in our study as we believe they are likely to be supported under the RO.

This compares with projected support cost of around £5.5bn at that time, and projected resource costs of around £4bn. However it should be noted that, since there is uncertainty around our derived strike prices and deployment projections, there is also a high level of uncertainty in the level of support costs required.

Beyond 2020, projected total support costs continue to rise as more low-carbon generation is deployed, even though the support cost per MWh declines. However the total resource cost (assessed against electricity prices based on the long run marginal cost of gas generation) stabilises at around £6-7bn (and start to decrease towards the end of the decade). The resource cost associated with offshore wind becomes relatively small, whilst nuclear has a negative net resource cost.

The difference between support costs and resource costs raises the question of how the Levy Control Framework cap should be defined. It is currently set as a cap on support costs, but it could be argued that this ignores the benefit of lower electricity prices associated with low-carbon generation.

4.9 Key messages

In this chapter we have derived projections for CfD strike prices required to bring forward low-carbon technologies in accordance with our deployment projections, based on our technology cost distributions. However there are significant uncertainties in this analysis, resulting both from inherent uncertainties in our deployment and cost projections, and from uncertainties in the detailed design of the CfD arrangements (for example around contract duration and measures for facilitating 'route to market').

Our key findings are as follows:

- The uncertainty around strike prices highlights the difficulty of determining strike prices through an administrative price-setting process, and hence the desirability of moving to competitive price discovery as soon as possible. We believe that onshore wind, offshore wind, and biomass conversions all offer the potential for competitive price discovery owing to the number of projects in each pipeline.
- It is important to consider whether strike prices should be determined as the price required by the marginal project required to meet desired deployment, or on an individual project basis. This consideration may be different for different technologies. In particular it may be appropriate to differentiate between different sub-technologies for CCS and nuclear, at least in the early to medium term, to avoid the risk of foreclosing some technology options and/or over-subsidising others.
- Our projections of required support costs are broadly in line with the Levy Control Framework to 2020, but there is a risk of exceeding the LCF levels[138].
- There will be a need for to increase the LCF cap beyond 2020 as the volume deployment of low-carbon generation increases, even though the required support per MWh decreases.
- The resource cost of this support may be much lower if carbon and fossil-fuel prices rise over time such that the cost of unabated gas–fired generation rises over time. This raises the question of how the Levy Control Framework cap should be defined.

138 More detailed analysis (beyond the scope of this study) is required here.

5. LOOKING BEYOND 2030

Although this study has focussed on deployment of low-carbon technologies out to 2030, this date is itself a milestone on the path to meeting the Climate Change Act target for the UK of reducing GHG emissions by at least 80% from 1990 levels by 2050[139]. In its Fourth Carbon Budget[140], the Committee presents analysis which shows that power sector emissions must fall to close to zero (around 5gCO_2/kWh) by 2050 if this target is to be met, and that the optimal path towards this involves achieving around 50gCO_2 /kWh by 2030.

In this chapter we consider qualitatively the implications of the timelines developed in Chapter 2 for further deployment of each low-carbon technology beyond 2030. In addition we consider what might be the implications of not meeting the 2030 timelines for further decarbonisation of the electricity generation sector out to 2050. We consider the implications both from an individual technology perspective (i.e. what is the potential to accelerate later deployment if certain milestones are not met in the period to 2030) and from an energy system perspective (i.e. what benefit does the diversified technology mix offer to manage delays or shortfalls in one particular technology deployment).

5.1 Individual technology considerations

In this sub-section we consider each technology in isolation. The post-2030 deployment potential for a particular technology depends on:

- how much of existing potential has been deployed and what actions have been taken, if any, to expand that capability (eg, new sites for nuclear or offshore); and
- if 2030 deployment ambitions have not been realised, what the reason for this is – eg, lack of commercialisation, slow supply chain build up.

As a result, the issues and constraints for deployment beyond 2030 will differ across technologies.

5.1.1 Offshore wind

The UK has a very large offshore wind resource and hence offshore wind has the potential to play a very significant role in the long term electricity mix. A previous Pöyry study for the Committee exploring technical constraints on low-carbon generation concluded that very high levels of offshore wind are feasible (for example around 90GW by 2050 in the ‘Very High’ scenario), provided sufficient actions are taken to improve electricity system flexibility[141].

In Chapter 2 we developed two plausible timelines for offshore wind deployment, reaching around 25GW and 40GW by 2030 in the lower and higher deployment scenarios respectively. If the higher deployment scenario is realised, then another offshore wind

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139 Excluding and negative emissions from the use of biomass with CCS.

140 CCC (2010)

141 Pöyry (2011). The study also concluded that development of floating turbine technology is likely to be a key facilitator of very high offshore wind deployment. In the ‘Very High’ scenario most growth beyond 2030 arises from floating turbines, with a small amount of growth coming from repowering of early fixed turbine sites.

leasing round is likely to be required in the 2020s to maintain the momentum of new projects into the 2030s. This may include sites for floating turbine projects.

The maximum deployment rates in the two scenarios are around 1.6GW/yr and 2.8GW/yr respectively. Even in the higher deployment scenario, annual deployment remains below 3GW – a figure regarded by a number of recent studies as achievable given appropriate policy ambition[142].

Table 15 – Potential for further offshore wind deployment

Deployment scenario	Installed capacity in 2030	Supply chain capacity by 2030	Maximum 2050 poetntial	Required deployment 2030-2050
Lower	25GW	1.6GW	90GW	3.25GW
Higher	40GW	2.8GW	90GW	2.5GW

Table 15 illustrates how the period before 2030 can influence the ability to achieve further deployment beyond 2030 – for example a target of 90GW by 2050. In our lower deployment scenario deployment is 25GW in 2030, requiring addition of new capacity at an average rate of 3.25GW/yr between 2030 and 2050 to reach 90GW. However the maximum supply chain capacity before 2030 is 1.6GW, meaning that a significant ramping up would be required to meet the much higher 2050 target. Furthermore, it is likely that a significant portion of the supply chain built up during the 2020s will need be deployed for repowering later in the 2030s, implying a requirement of for a gross supply chain capacity greater than 3.25GW/yr in this example.

By contrast, in the higher deployment scenario deployment rates reach up to 2.8GW/yr before 2030, achieving 40GW of installed capacity by that date. Further deployment to 90GW in 2050 can be achieved at a similar deployment rate, although again the gross supply chain capacity will need to continue to expand to accommodate repowering.

This example illustrates the general point for all technologies that if high deployment rates and build-up of supply chain capacity can be achieved by 2030, then even higher deployment beyond 2030 is facilitated because the supply chain will be better equipped to achieve these higher deployment rates. Conversely, if deployment by 2030 falls well short of expectations, it is likely that supply chain capacity at that point will be at much lower levels making it harder to achieve significant deployment thereafter.

We recognise that offshore wind is currently one of the more expensive low-carbon technologies, and that Government support for very high deployment is likely to be predicated on significant cost reductions (at least in relation to other alternatives). However there is an expectation that increased deployment itself will facilitate future cost reductions as the industry gains more experience and investors become more comfortable with the technology – hence creating a 'virtuous circle' of higher deployment and lower costs as the industry matures.

142 EC Harris (2012), BVG (2011)

5.1.2 Onshore wind

For onshore wind, we conclude in Chapter 2 that there is no clear consensus on what might be the ultimate limit to onshore wind deployment. We estimate that the UK currently has an onshore capacity density of around 20kW/km^2. This is significantly below other some other European countries – for example around 45kW/km^2 in Spain and 80kW/km^2 in Germany – and indicates that there may be scope for significantly more deployment (whilst recognising that there may be country-specific factors affecting deployment in different countries). In reality, the limit on onshore wind deployment may be driven more by public acceptability rather than the availability of suitable land per se.

In our timeline we assume that the number of projects coming forward and achieving planning consent declines in the 2020s as a result of the best and most acceptable sites being used up, although our assumptions here are somewhat arbitrary given the absence of evidence in this area. Our timeline achieves deployment of around 25GW by 2030. Annual deployment rates in the 2020s reach around 1.2GW/yr.

However we expect that the lack of new sites will be offset to some extent by the potential to repower existing sites with newer improved turbines. Most of the capacity installed in recent years will be reaching the end of its life, thus offering a significant potential for repowering in the 2030s. For example in 2030 we project around 300MW of repowered capacity will be added, and this will increase as more projects reach the end of their operating lives. Thus supply chain capacity built up before 2030 can be diverted to repowering projects if or when the supply of new sites begins to decline.

Note that repowering may also offer the potential to significantly increase onshore wind deployment without finding additional sites (although there may still be challenges in obtaining planning consent if the repowering of a site involves adding taller turbines). As for offshore wind, the upper limit for onshore wind deployment may be predicated on sufficient actions being taken to improve electricity system flexibility.

Although the upper limit on onshore wind deployment is not known, our expectation is that our projected deployment of 25GW by 2030 represents a significant proportion of this, and that addition of further capacity is likely to be lower beyond 2030 than before 2030. Hence if deployment to 2030 is below our projections it may still be possible to ‘catch up’ and achieve the full potential by 2050.

5.1.3 Nuclear

Nuclear power has a key role to play in future decarbonisation of the electricity grid given that it is an established technology, it is controllable, and the evidence base suggests it is one of the cheaper low-carbon technologies. It is likely that nuclear capacity will need to continue to grow beyond 2030 (beyond merely replacing the existing fleet) if the grid is to be almost fully decarbonised by 2050.

Our projected timeline for nuclear deployment achieves around 16GW by 2030, limited primarily by the availability of developers and construction finance. However, if our timeline is achieved, then in 2030 there will be three developers each with experience of building several reactors in the UK. In this scenario a supply chain will be established and the technology de-risked for investors. This may encourage additional developers to enter the market. At the same time, the existing developers are more likely to be able to part-sell existing operational projects in order to recycle capital for new projects.

As discussed in Chapter 2, there is the potential to develop the three remaining sites identified in the National Policy Statement for Nuclear[143] – these might contribute around another 7GW depending on how much capacity can be developed on each site. If this deployment scenario is realised, then further sites will need to be identified towards the end of this decade in order to maintain the momentum of new projects into the 2030s.

Our projected deployment timeline encompasses a progressive build-out of new projects to allow a relatively steady build-up of UK supply chain capacity. Projects are phased so that the workforce employed in one project is available to move onto the next project. Hence successful deployment of projects in the 2020s is likely to leave a legacy of an established supply chain and experienced workforce available for further projects on the 2030s.

Conversely, failure to deliver a series of projects in the 2020s will make a significant roll-out by 2050 even more challenging (as for offshore wind). The very long lead times for nuclear projects mean that it is even more important (compared to offshore wind, for example) that new nuclear plants are operational by 2030, since it will be harder to 'catch-up' after that point. A pre-requisite for 'catching-up' in the 2030s if deployment in the 2020s is below our projections is that there are sufficient developers and investors available at that point to support the higher deployment rates required – this might be considered less likely if the UK has failed to attract nuclear investment in the 2020s.

5.1.4 CCS

Compared to the other technologies assessed in this study, CCS is the least mature. In 2009 Pöyry undertook a study for the Committee looking at the potential for CCS deployment to 2030[144]. The study concluded that 10-20GW was achievable, but this was predicated particularly on early action to support the first pre-commercialisation projects. In the intervening period there has been little progress in developing the first pre-commercialisation projects, and hence our deployment projection for 2030 is now at the lower end of this range. Our timeline now foresees commercial roll-out starting in the late 2020s, based on an assumption that investors will commit to these projects once the first phase pre-commercial projects are successfully operating, but whilst the second phase pre-commercial projects are still under construction.

This is an aggressive deployment projection, and is predicated on the assumption that the Government is able to persuade investors of a long term commitment to CCS. As CCS is one of the more expensive low-carbon technologies, it is particularly important that Government adopts policies which de-risk CCS and hence reduces the rate of return required by investors. A key element of this, identified by the UK CCS Cost Reduction Taskforce[145], is the need for a clear vision for the development of an integrated CO_2 transport and storage infrastructure.

Some commentators assert that switching from coal to gas is a more cost-effective means of decarbonising the grid in the medium term than increasing renewable generation (although it is highly unlikely that this strategy would achieve 50gCO_2/kWh by 2030). If there is indeed a further 'dash for gas' in the next decade or so to replace retiring coal and nuclear stations, then it is even more important that CCS is established as a proven technology by 2030 (with a well-developed T&S infrastructure), to facilitate retro-fitting of

143 DECC (2011b)

144 Pöyry (2009)

145 CCS CRTF (2012)

CCS to these gas-fired plants in the 2030s. If there is a significant gas-fired fleet in 2030 and there has been no progress on CCS by then, the ability to decarbonise the grid by 2030 will be significantly reduced owing to the long lead time required for this technology to mature.

5.1.5 Biomass

The scope for relying on electricity from biomass in the long term will depend on the availability of suitable sustainable feed-stocks. In the absence of any significant growth in biomass availability, we assume that Government policy will be that biomass is preferentially for other applications where there are fewer low-carbon alternatives, such as aircraft fuels or high temperature process heat, in line with the DECC and CCC Bioenergy Strategies[146].

Hence our timeline suggests that biomass conversion is seen as a ‘transition technology’ with little or no role after 2030. Note however that there may be a role for biomass power generation with CCS, if CCS is successfully established in the long term, as biomass CCS offers the potential for ‘negative’ carbon emissions. This adds to the importance of establishing CCS as a credible long term low-carbon technology.

5.2 Impact on system decarbonisation

It is beyond the scope of this study to examine the level and exact mix of low-carbon technologies required to meet decarbonisation targets in 2050 (or even in 2030). However the expectation is that significant installed capacities of onshore and offshore wind, nuclear, and CCS will all be need to essentially decarbonise the grid by 2050. The discussion above suggests that it will be increasingly hard to ‘catch-up’ between 2030 and 2050 if deployment to 2030 falls significantly behind our projected timelines. In addition, if one technology fails to deploy as projected, then this will place an additional burden on other technologies to fill the gap. Clearly it will be preferable to have well developed supply chains across all technologies by 2030 in order to maximise the options available for meeting the 2050 target.

The extent to which it is possible for deployment of a technology to ‘catch-up’ between 2030 and 2050 if deployment to 2030 falls significantly behind our projected timelines will vary across technologies. For example onshore wind deployment is likely to slow beyond 2030 as the number of available sites declines, so it is likely that a delay in developing sites before 2030 can be recovered later. For offshore wind there may be possible to recover and delays in deployment through a more aggressive ramping up of supply chain capacity (although this is still likely to be challenging than a more gradual build up). Nuclear and CCS projects generally have longer lead times and so the opportunity to recover any delays in roll-out will be more limited, particularly if the required supply chain infrastructure is not fully developed by 2030.

146 DECC (2012b), CCC (2011).

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ANNEX A – SUMMARY OF COST INPUT ASSUMPTIONS

This Annex provides additional detail in relation to important input cost assumptions used to derive levelised cost distributions in Chapter 3.

A.1 Offshore wind

For offshore wind we have derived cost distributions drawing on an existing in-house database of UK offshore wind project costs. This has been developed through a bottom-up costing of all uncommitted projects, allowing us to take into account specific project cost drivers such as location, depth, distance from shore, and wind conditions and differentiate between projects.

The list of projects comprises all of the undeveloped projects for which The Crown Estate has awarded licences – these include Round 3 projects, Scottish Territorial Waters projects, and Round 2 projects (and Round 1 or 2 extensions) which have not yet reached financial close[147]. This approach allows us to capture cost differences between projects arising through the various cost drivers such as geographic location, water depth, distance from shore, and turbine size. Our list comprises 64 projects in total.

A.1.1 Cost drivers

The levelised cost of a wind farm is a function of a number of input variables: capital cost, operating cost, load factor, project life, build time, and required rate of return. In our analysis we assume the first three items are project specific, while the latter three are the same across all projects (except that the required rate of return may be a function of when a project is committed).

For the project specific cost items, we broke each of these down into a number of sub-components as shown in Table 16. We then identified the key drivers for these sub-component costs, and hence derived an assumption for each sub-component for each project based input assumptions for each of these key drivers. For a given project there is generally information available about its location, the number and size of turbines it might use, and the landing point for the export cable. (Where such information is not variable we have made informed assumptions.)

As an example, our approach to deriving OFTO charges was as follows:

- Specify basic design choices such as AC or DC link and number of offshore substations based on project size and distance from shore.
- Estimate costs of basic components – offshore substations, export cable (offshore and onshore), and onshore substation works – based on in-house engineering experience of offshore wind projects. The cable costs are a function of length, which is either known from developer websites or can be derived from the locations of the project and the point of connection to the onshore grid. This length is then combined with an assumption regarding the installed cost per kilometre of cable.
- Convert the total capital cost to an annual OFTO charge. We assume that the annual OFTO charge is 11% of the estimated capital cost (including interest during construction) of the OFTO assets. This conversion factor is based on an assessment of OFTO licence awards to date.

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147 Where licensed zones will be developed in phases we have considered each phase as a separate project.

- The resulting range of OFTO charges is £23-114/kW/yr. This very wide range reflects the wide range of capital costs of OFTO assets, driven primarily by distance of the wind farm offshore and also wind capacity (which impacts the £/MW cost of an OFTO connection).

Table 16 – Breakdown of cost components and drivers

Cost component	Cost sub-component	Main drivers of cost differences
Capex	Foundation supply	Turbine size, water depth, foundation type
	Turbine supply	Turbine size
	Installation costs	Wave conditions, distance from shore
	Within-array electrical system	Turbine spacing, project size
	Other (e.g. contingency)	
Opex	O&M costs	Distance from shore, wave conditions, turbine size
	OFTO charges	Length of export cable
	Onshore TNUoS charges	Location of landing point
	Other (e.g. insurance, lease payments)	
Load factor	Turbine load factor	Wind speed
	Wake losses	Turbine spacing, number of turbines
	Availability	Distance from shore, wave conditions
	Other losses (e.g. electrical)	

A.1.2 Cost component results

The result of this process is a set of assumptions for the cost sub-components for each project. These are then combined to give a value for capital cost, operating cost, and load factor for each project. Table 17 below shows the range of values derived across the range of 64 projects. We show 10th and 90th percentile values as well as minimum and maximum to show where there are extreme outliers to the range. Note that all of these values are 'central' cost estimates for each project before taking account of uncertainty in the cost estimation process. (They are also 'current cost' estimates before taking account of learning rates and reducing discount rates over time – see Section 3.2.4 – but including the benefit of using the next generation of large wind turbines).

Table 17 – Distribution of cost component assumptions for offshore wind projects

	Capex (£m/MW)	Opex (£/kW/yr)	Load factor
Minimum	2.37	113	37.1%
10th percentile	2.45	122	40.3%
Median	2.79	172	25.6%
90th percentile	2.98	214	47.2%
Maximum	3.26	279	52.9%

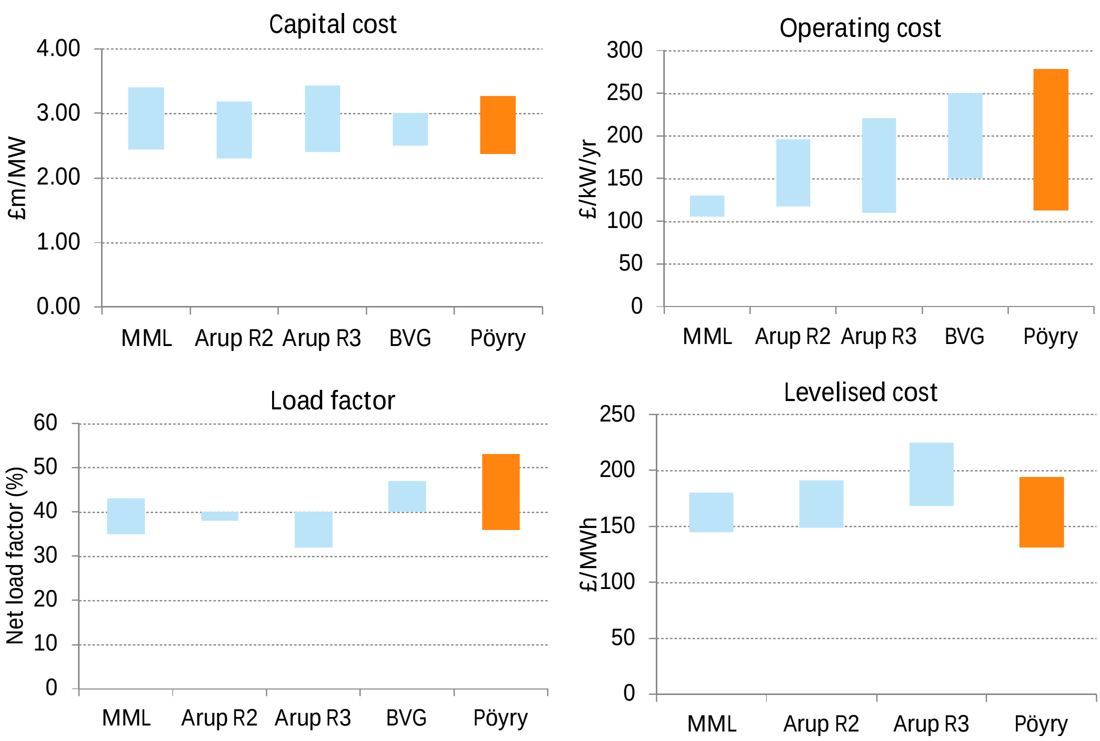
For all projects, we assume:

- an operating lifetime of 22 years;
- a build time of 3 years; and
- a required rate of return of 12.4% (pre-tax real), assuming FID occurs before 2016 (see Section 3.2.4 for our assumptions of how tis changes over time).

A.1.3 Validation of results against evidence base

In Figure 45 we compare the range of assumptions we have derived for the key cost components of the levelised cost calculation with estimates published in other recent studies (all before taking account of learning effects). Our results are broadly consistent with these other studies. We have wider ranges for operating cost and load factor, perhaps reflecting the fact that we have assessed 64 individual projects – the variation in operating cost reflects the wide range of OFTO charges we have derived. Note that our ranges reflect the range across projects but are based on 'central cost' estimates for a given project – they do not take into account cost uncertainty for a given project.

Figure 45 – Comparison with cost estimates for offshore wind from other sources



Source: Pöyry analysis of:
MML MML (2011b)
Arup R2 Arup (2011) non-Round 2 projects (i.e. Round 2, Scottish Territorial Waters, extensions)
Arup R3 Arup (2011) Round 3 projects
BVG BVG (2012b)

A.2 Onshore wind

A.2.1 Methodology

For onshore wind the large number of projects means that it is not practical in this study to assess costs for individual projects. We have modelled a supply curve based on grouping of projects into different cost categories and geographic zones in order to construct a detailed cost distribution reflecting the full range of pipeline projects:

- We define nine different project cost categories, differentiated by project capacity and distance from grid, as these variables are considered to be key differentiators of capital cost between projects. Larger projects are able to spread certain costs across a greater output and so benefit from economies of scale. Distance to grid will

determine the electrical connection cost for a project, and this can vary significantly between projects depending on their location relative to the nearest network (see Table 18).

Table 18 – Onshore wind project cost categories

Number of projects

	Distance to grid (km)		
Size (MW)	< 2	2-10	> 10
< 5	98	115	9
5-50	87	217	19
> 50	9	31	13

Capacity (MW)

	Distance to grid (km)		
Size (MW)	< 2	2-10	> 10
< 5	159	152	15
5-50	1303	4016	508
> 50	895	2539	1842

The first table shows the number of existing pipeline projects in each category, while the second shows the total capacity in each category.
Source: Pöyry analysis of Renewable UK Wind Energy Database (snapshot mid-January 2013)

- We then derive estimates for capital and operating costs for these generic project types, based on our in-house engineering expertise of a number of onshore wind projects in the UK and in Europe.
- For information on the current pipeline of onshore wind projects, we use a snapshot (taken in mid-January 2012) of projects reported as in planning or consented in Renewable UK's Wind Energy Database. We then assign these projects the nine project categories based on their size and location, using GIS mapping to determine distance to the nearest electricity network. Table 18 shows the distribution of projects across the different cost categories by number of projects and capacity. In total there are around 600 projects totalling around 11GW of capacity. Note that for the purposes of this project we have derived costs only for projects greater than 5MW in capacity, as smaller wind farms will not be eligible for CfD FiTs (but will continue to be eligible for small-scale FiTs).
- We also use a project's location to assign it to one of 27 geographic zones corresponding to the latest zones used by National Grid for Generator TNUoS charging purposes[148] [149]. This allows us to capture the geographic variation in grid use of system charges. TNUoS charges range from -£5/kW/yr in South West England to +£30/kW/yr in North West Scotland.
- We also calculate typical load factors for three different turbine heights for (a different set of) fifteen geographic zones, using our database of historic wind data (provided by Anemos) and assumed turbine performance curves. This allows us to assign each project a load factor based on its hub height and location and hence reflect broad geographic variation in load factors. (We also adjust load factors for assumed availability and wake losses at this stage.)
- This allows us to develop a high resolution supply curve for the existing pipeline.

148 NGC (2013b). We use 2013/14 tariffs as assessing how these might change over time is outside the scope of this report.

149 We also define Northern Ireland as a geographic zone as we consider the full UK pipeline.

A.2.2 Cost component results

The result of this process is a set of assumptions for the cost sub-components for each project. These are then combined to give a value for capital cost, operating cost, and load factor for each project. Table 17 below shows the range of values derived across the full range of projects greater than 5MW. We show 10th and 90th percentile values as well as minimum and maximum to show where there are extreme outliers to the range[150]. Note that all of these values are 'central' cost estimates for each project before taking account of uncertainty in the cost estimation process – which might be around ±20% for capital cost, for example. Note also that they are 'current' costs before application of learning effects (if any) over time.

Table 19 – Distribution of cost component assumptions for existing pipeline onshore wind projects above 5MW

	Capex (£m/MW)	Opex (£/kW/yr)	Load factor
Minimum	1.22	37	21.9%
10th percentile	1.22	48	24.2%
Median	1.36	54	27.6%
90th percentile	1.36	68	29.8%
Maximum	1.47	73	31.2%

For all projects, we assume:

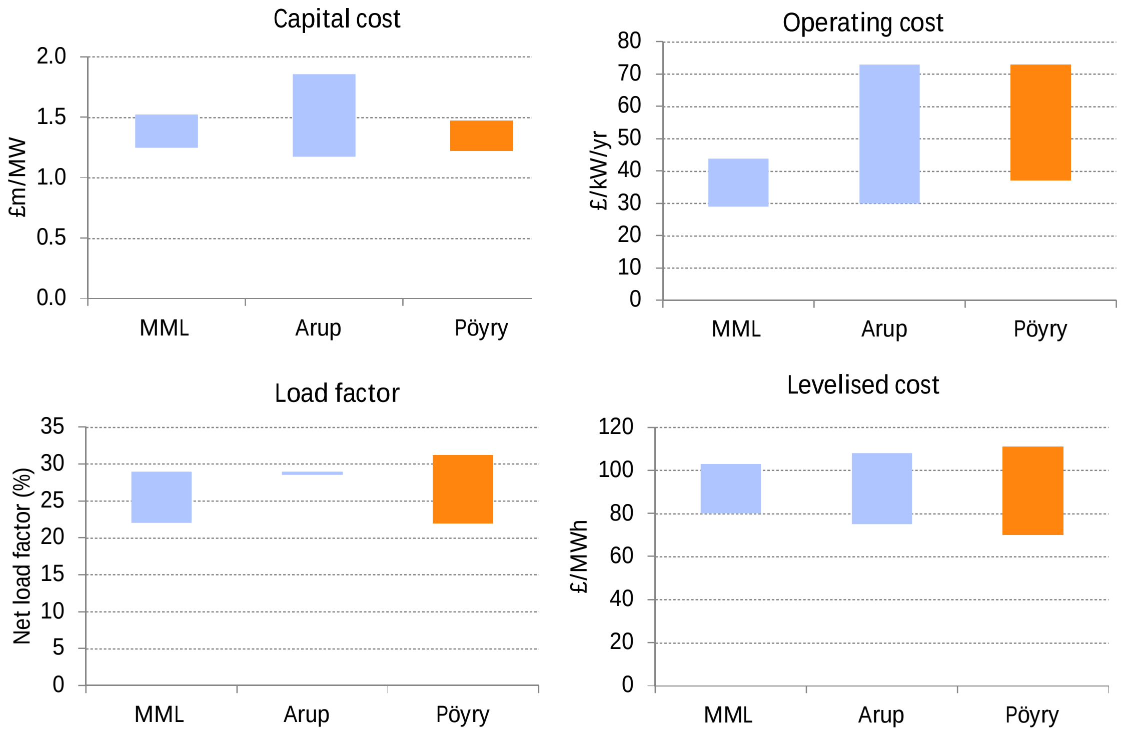
- an operating lifetime of 24 years;
- a build time of 2 years; and
- a required rate of return of 9.6% (pre-tax real), assuming FID occurs before 2016 (see Section 3.2.4 for our assumptions of how this changes over time).

A.2.3 Validation of results against evidence base

In Figure 45 we compare the range of assumptions we have derived for the key cost components of the levelised cost calculation with estimates published in the Mott MacDonald and Arup studies (all before taking account of learning effects). Our results are broadly consistent with these other studies. Note that our ranges reflect the range across projects but are based on 'central cost' estimates for a given project – they do not take into account cost uncertainty for a given project.

150 For capital costs each project cost category has a single assumption, and so there are only six possible values – hence some of the values in the Table are the same.

Figure 46 – Comparison with cost estimates for onshore wind from other sources



Source: Pöyry analysis of:
MML MML (2011b)
Arup Arup (2011)

A.3 Nuclear

In this section we consider in turn the various cost components feeding into the levelised cost calculation for nuclear projects. We then present the assumptions used to derive the cost distributions presented in Section 3.4.

A.3.1 Capital costs

Predevelopment

It is generally reported that EDF costs to date are approximately £1bn, covering early site work (at Hinkley Point and Sizewell), growth and staffing of the development company, licensing and permitting activities, parent company support, vendor design and engineering support. This investment has enabled the project at Hinkley Point to become 'shovel ready' (ready to commence nuclear plant construction) pending a positive conclusion to the Contracts for Difference (CfD) negotiations with the government and EDF taking a final investment decision (FID) (EDF statement Dec 2012). We have assumed that a portion of this reported cost relates to Sizewell and have therefore apportioned the cost across both sites, and reflecting that some costs fall disproportionately upon the first unit(s). Our analysis of apportioned costs aligns with the latest published estimates used by DECC[151].

151 PB (2012)

Regulatory/ Licensing

Recent seminars have indicated the costs incurred by the stakeholder parties for the GDA, and for site licensing costs. For the EPR and AP1000 the reported cost of the assessment process by ONR and EA is £32m for each technology. This is assumed to be equally divided across the 4 identified EPR plants, i.e. £8m per unit. Site licensing costs (for Hinkley Point C) are quoted at £8m, which is attributed to each unit – this may be conservative, but reflects future activities as issues inevitably arise and are resolved. This represents an increase over the estimates used by DECC[152], with an indicated contribution of £10/kW (compared to £2.9/ kW previously).

Construction

Recent press reports and other articles (ICEPT Working Paper, 2012) have suggested that the construction cost of EPR could be £7bn[153] or more for a single unit EPR plant under construction at Olkiluoto-3 (Finland) or Flammanville-3 (France). In Section 2.4.2 we suggest reasons for the escalation of costs for these plants, and the element of learning and pre-construction activities that put these projections at the high end of our analysis. The Parsons Brinckerhoff estimates prepared for DECC predict a capex cost of £6.1bn (£3,824/kW) and we see no reason to change this as a best estimate.

Infrastructure

All the proposed UK nuclear sites are coastal sites with established grid connections, with a degree of remoteness and low population density. Thus, in general each site is broadly similar, and as above, in the absence of information to indicate otherwise we have adopted the assumption of £11.5m for local site development[154]. We note that the sites at Wylfa and Moorside may have some logistic aspects which might increase the infrastructure development costs (e.g. restrictions on transport links for construction teams or marine off-loading access), but consider these aspects to be minor in the overall accuracy of the cost estimate. We have not considered any costs required for wider transmission system reinforcement (as these would be socialised in TNUoS charges).

A.3.2 Operating costs

We are not aware of any information to contradict or change the range quoted in Table 21 and have retained the fixed O&M cost for PWR. For ABWR, there is information available from operating plants, albeit from the Far East, which indicates operating staff numbers some 10% lower than for PWR. We have elected not to adopt this reduced figure for ABWR as there is some uncertainty whether this benefit can transfer to the UK market.

Fuel

Forecasts of uranium fuel supply have not changed since the 2011 Mott MacDonald study for the Committee[155]. If anything the present market demand and identified future over-capacity might suggest further reduction in fuel price, but we have elected not to speculate on this and retain the earlier figures.

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152 PB (2012)

153 Reported figure of €8bn converted to pound sterling at exchange rate of 1.15

154 PB (2012)

155 MML (2011b)

Although there will be differences in costs between PWR and ABWR fuel principally arising from the lower enrichments in ABWR, the effect on overall operating costs will be small and for this study are ignored.

Waste and decommissioning

DECC has recently issued guidance on the lifetime costs associated with provisions for future decommissioning and waste storage/ disposal of nuclear waste arising. These later figures are adopted in the model, noting that the change to the contribution to overall costs is so small to be negligible.

Insurance

Two key factors influencing insurance costs are identified: response to Fukushima and the potential costs associated with a similar nuclear accident; and, changes to the liabilities required to be covered by nuclear plant operators according to the Brussels Convention. Although no details are provided in the DECC assumptions, we assume from the timing of the PB report that these aspects are already captured and accounted for in the model, and hence make no further amendment.

Although in theory, there will be differences between technologies and plant designs in relation to the public and environmental risk to be covered by insurances, since the prospective plants are all 'large' reactors differences in off-site consequences associated with similar low probability severe accidents will be small enough to be ignored. PWR and ABWR are thus treated equally.

A.3.3 Plant operations

Development time and plant life

We have no evidence to suggest the range of time for predevelopment and the time for construction published by PB for the PWR (see Table 21) requires updating.

Predevelopment includes all site preparations including licensing and planning that are required prior to the pouring of first nuclear concrete. Construction time includes the engineering procurement and construction (EPC) of reactors and any infrastructure development. While the two on-going PWR projects in Europe at Flammanville and Olkiluoto have experienced construction overruns, there is no reason to presume that the same issues will be encountered in the UK and the fact that the UK has implemented a GDA process the expectation is that construction estimates are achievable.

Across the evidence base there is an assumption that the nuclear plant lifetime will be 60 years as this is the technical lifetime of the new PWR reactors. We have adopted this figure.

Availability

In our view the availability assumption from the evidence base is technically achievable but possibly optimistic. The principal reason for making this observation is that the actual availability achieved by an individual nuclear plant does not seem to be driven by the reactor technology but is driven by the utility operator. Historically operators in the US and Germany have achieved high availability factors while France and Japan have low availability.

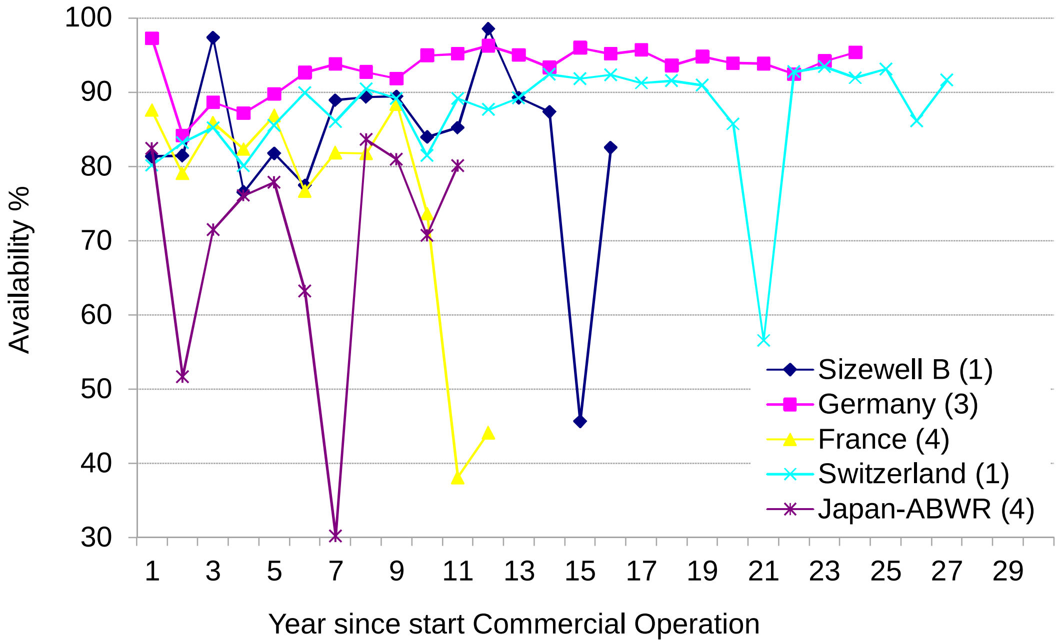
As with all generating plants, periodic shutdown for planned and unplanned maintenance and plant modification will arise, reducing the amount of electricity sent to the grid, and

therefore revenue earned. Therefore reducing the time taken for plant maintenance and maintaining a high availability is desirable. Observers of the operation of power plants in different countries have found that the operating and maintenance culture can produce significantly different annualised outputs for comparable plants. Thus performance in one jurisdiction is indicative of potential performance, but underlying factors may also be relevant. Some commentators have suggested that recent uplift in US performance is due to driving these plants harder (while complying with regulatory safety limits), than may be practised in other, more conservative, utilities and countries. Quoted design availability figures for latest nuclear plants are around 92%, although very few existing plants achieve this level for any substantial operating period (years). Thus we are sceptical that such figures can be achieved over the lifetime of the plant.

Figure 47 shows annual availability factors for a number of plants relevant to UK applications including:

- French N4 and Germany's Konvoi, indicative of PWR;
- Sizewell B (the UK's existing PWR plant); and
- four operating ABWR plants, together with Leibstadt (Switzerland) (which is a fore-runner of ABWR).

Figure 47 – Historic annual availability performance of nuclear facilities grouped by country



Source: Pöyry analysis based on IAEA PRIS data

Based on these observations we have used the availability assumptions for PWR from the evidence base but altered the assumptions for the ABWR. In our modelling we have assumed a best estimate availability of 87%, and a low scenario of 75% and a high scenario of 90%.

These availability estimates assume that nuclear power plants run at baseload operation. It is worth noting that the latest plants are capable of load follow operation, but to date UK

utilities have seen no requirement to formally licence this mode of operation. The presumption (of baseload operation) is assumed to be valid for the foreseeable developments to 2030, but subsequent build may need to recognise the need for flexibility of generating output as nuclear competes for a larger share of the market[156].

A.3.4 Summary of cost assumptions

Table 20 shows the central case current cost assumptions we have used to derive levelised costs, whilst Table 21 shows the ranges for these assumptions which we used in sensitivity analysis to explore the impact of cost uncertainty on derived CfD strike prices.

[156] Dispatch modelling is beyond the scope of this study.

Table 20 – Central nuclear current cost assumptions

		PWR		ABWR	
		FOAK	NOAK	FOAK	NOAK
General assumptions					
Predevelopment	yrs	5	5	5	4
Construction	yrs	6	5	5	5
Plant life	yrs	60	60	60	60
Availability	%	91%	91%	85%	87%
Capex					
Predevelopment costs	£,000/MW	188	160	232	196
Regulatory costs	£,000/MW	3	3	3	3
Construction cost	£,000/MW	3824	3250	3250	2763
Infrastructure cost	£,000	11500	11500	11500	11500
Opex					
Fixed O&M	£/kW/yr	72	60	72	60
Vble O&M	£/MWh	2.6	2.5	2.6	2.5
Fuel	£/MWh	5.2	5.2	5.2	5.2
Waste&decom	£/MWh	2.5	2.5	2.5	2.5
Insurance	£/kW/yr	10	10	10	10
Grid UoS	£/kW/yr	4.5	4.5	4.5	4.5

Source: PB (2012) with additional Pöyry analysis .
Infrastructure cost is as defined in PB (2012) and includes constructions costs outside the site boundary (e.g. local grid connection works).

Table 21 – Range of current cost assumptions for nuclear

		PWR		ABWR	
		FOAK	NOAK	FOAK	NOAK
General assumptions					
Predevelopment	yrs	5 - 7	5 - 7	4 - 6	3 - 5
Construction	yrs	5 - 8	5 - 8	4.5 - 7	4 - 6
Plant life	yrs	60		60	
Availability	%	90 - 92		75 - 90	
Capex					
Predevelopment costs	£,000/MW	104 - 408	88 - 346	128 - 502	108 - 426
Regulatory costs	£,000/MW	2 - 4		2 - 4	
Construction cost	£,000/MW	3529 - 4118	3000 - 3500	3000 - 3501	2550 - 2975
Infrastructure cost	£,000	0 - 23000		0 - 23000	
Opex					
Fixed O&M	£/kW/yr	60 - 84	50 - 70	60 - 84	50 - 70
Vble O&M	£/MWh	2.6 - 2.6	2.5 - 2.5	2.6 - 2.6	2.5 - 2.5
Fuel	£/MWh	4.2 - 6.3		4.2 - 6.3	
Waste&decom	£/MWh	2 - 3		2 - 3	
Insurance	£/kW/yr	8 - 12		8 - 12	
Grid UoS	£/kW/yr	4.5 - 4.5		4.5 - 4.5	

Source: PB (2012) with additional Pöyry analysis

A.4 CCS

A.4.1 Comparison of evidence base

Owing to the large number of CCS technologies, a detailed comparison across studies of every input cost assumption for calculating levelised costs is not practical. In this section we compare some of the key parameters including the resulting levelised costs themselves. The key sources we have reviewed are:

- the 2012 Parsons Brinckerhoff (PB) study for DECC[157];
- Mott MacDonald's 2011 study for the Committee[158]: and
- The UK CCS Cost Reduction Task Force's (CRTF) Interim Report, itself largely based on a 2012 Mott MacDonald Study for DECC[159].

It is not straightforward to compare UK CCS Cost Reduction Task Force evidence and the PB study as the former assesses costs by FID date and the latter uses the FOAK/NOAK concept. Based on our timeline (see Section 2.5), the first commercial phase projects (i.e. FOAK projects) reach financial close in the early 2020s and so are broadly comparable to the CRTF 2020 data, whilst NOAK projects have FID dates in the later 2020s. The CRTF 2013 estimates may be thought of as relating to pre-commercial projects ('zero-th of a kind' or ZOAK).

Figure 48 compares the capital cost estimates across these studies. Along with fuel price and discount rate, capital cost is a major driver of the levelised cost of CCS. For all studies the capital cost of coal-based technologies is greater than for gas, and there is little difference between the three coal technologies. The PB study is the only one to look at pre-combustion gas CCS, and it estimates a similar capital cost (but slightly more expensive) compared to post-combustion gas. Compared to the CRTF estimates, the PB study has lower capital costs for coal IGCC and oxy-fuel, higher for coal post-combustion, and broadly similar for gas post-combustion.

Owing to the large number of different sub-technologies, we do not include here a detailed comparison across the evidence base of the other input assumptions to the levelised cost calculation, such as operating costs, plant efficiency, and load factor. Instead, in Figure 49, we show levelised costs based on the information in these studies[160]. A key point is that the differential between coal and gas is much reduced (compared to the differential in capital costs), owing to the fact that gas prices are higher than coal prices. Although gas CCS appears to have a marginally lower levelised cost, the range of uncertainty in the levelised costs means that it is not clear which technology will ultimately be the most cost-effective.

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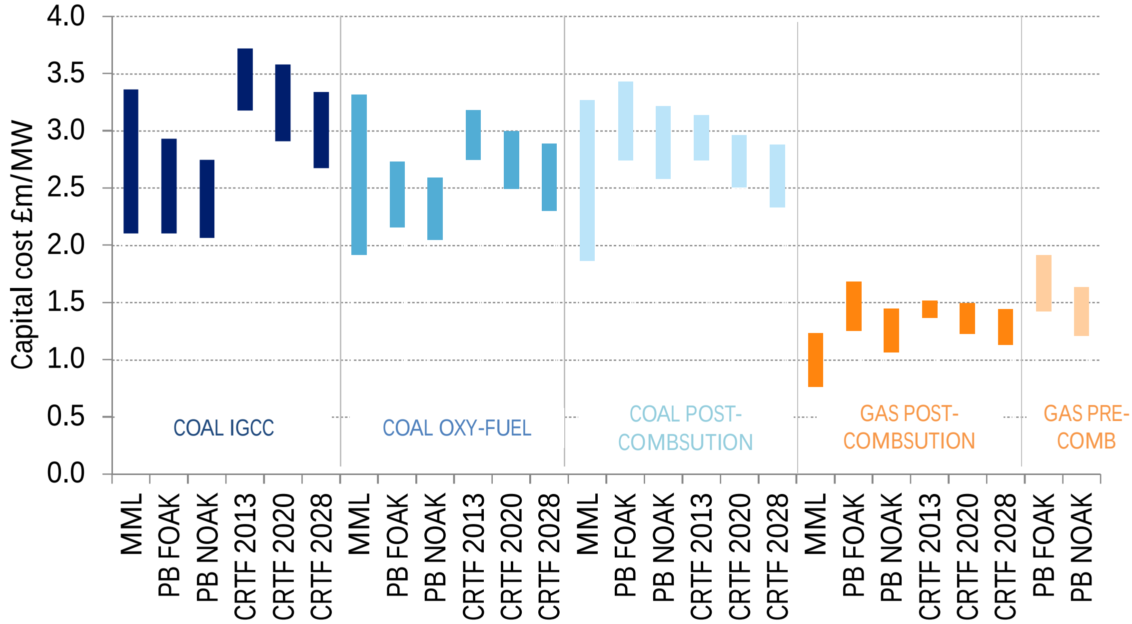
157 PB (2012)

158 MML (2011b)

159 CCS CRTF (2012) and MML (2012)

160 Not all of the studies present levelised costs so we have derived this based on the input assumptions reported. Note however that the different studies may use different assumptions for fuel and carbon prices and so may not be directly comparable.

Figure 48 – CCS capital cost estimates: comparison of evidence base

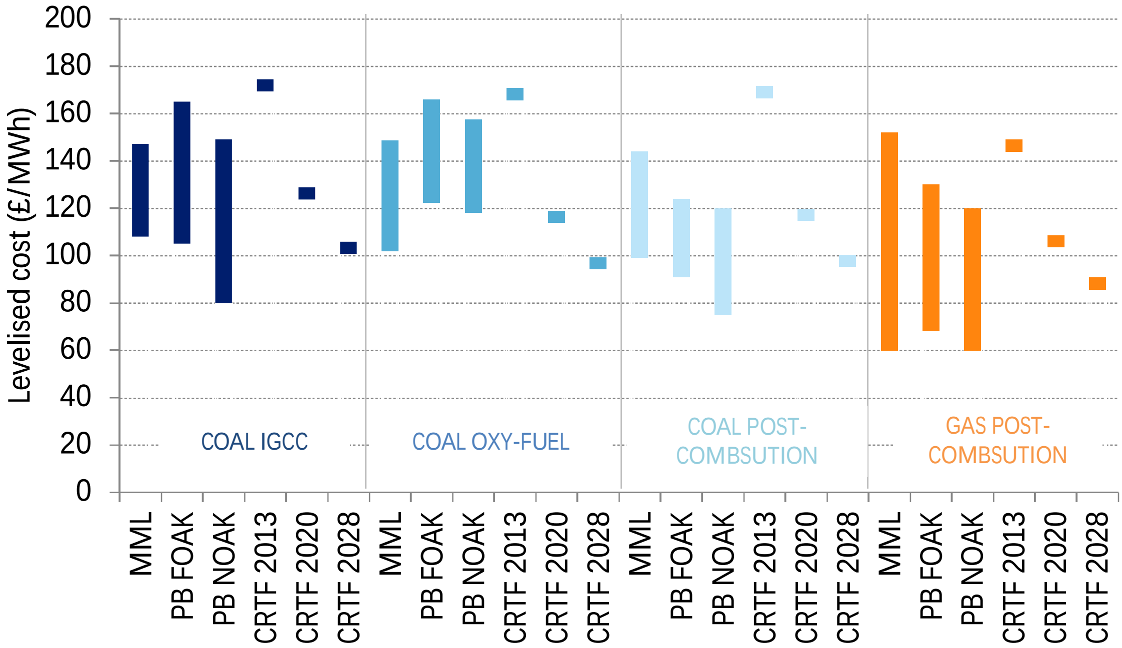


Source: Pöyry analysis of the following studies:

MML	MML (2011b), current cost NOAK values
PB FOAK	PB (2012) FOAK values
PB NOAK	PB (2012) NOAK values
CRTF 2013	CCS CRTF (2012) values quoted for 2013 FID date
CRTF 2020	CCS CRTF (2012) values quoted for 2020 FID date
CRTF 2028	CCS CRTF (2012) values quoted for 2013 FID date

The CRTF values show the range of values taken from the low and high cost paths outlined in MML (2012)

Figure 49 – CCS levelised costs: comparison of values derived from evidence base



Source: Pöyry analysis of the following studies:

MML	MML (2011b), current cost NOAK values
PB FOAK	PB (2012) FOAK values
PB NOAK	PB (2012) NOAK values
CRTF 2013	CCS CRTF (2012) values quoted for 2013 FID date
CRTF 2020	CCS CRTF (2012) values quoted for 2020 FID date
CRTF 2028	CCS CRTF (2012) values quoted for 2013 FID date

The CRTF values are based on the 'adjusted path' values adopted by the Task Force in CS CRTF (2012)
Gas pre-combustion not shown as this is not assessed in MML or CRTF

A.4.2 Summary of cost assumptions

Table 20 shows the central case current cost assumptions we have used to derive levelised costs, whilst Table 21 shows the ranges for these assumptions which we used in sensitivity analysis to explore the impact of cost uncertainty on derived CfD strike prices. In general these assumptions are based on the Parsons Brinckerhoff study[161].

161 PB (2012)

Table 22 – Central cost assumptions for coal CCS

		Coal IGCC			Coal Oxy-fuel			Coal post-combustion		
		ZOAK	FOAK	NOAK	ZOAK	FOAK	NOAK	ZOAK	FOAK	NOAK
Operations										
Predevelopment	yrs	5.25	5.25	4.5	6	6	4.5	5.3	5.3	4.5
Construction	yrs	6	6	5.5	6	6	4.5	5	5	4.5
Plant life	yrs	25	25	30	25	25	30	25	25	30
Availability	%	90%	90%	90%	90%	90%	90%	96%	96%	96%
Efficiency (HHV)	%	32%	32%	33%	33%	33%	34%	32%	32%	33%
CO2 scrubbing	%	89%	89%	89%	93%	93%	95%	89%	89%	90%
Capex										
Predevelopment costs	£,000/MW	45	30	25	40	27	23	38	25	23
Regulatory costs	£,000/MW	1	0	0	1	0	0	0	0	0
Construction cost	£,000/MW	3693	2462	2374	3599	2399	2285	4508	3005	2824
Infrastructure cost	£,000	11250	7500	7500	11250	7500	7500	11250	7500	7500
Opex										
Fixed O&M	£/kW/yr	61	61	55	57	57	53	76	76	64
Vble O&M	£/MWh	2.3	2.3	2.0	2.4	2.4	2.3	2.5	2.5	2.1
Insurance	£/kW/yr	3.7	3.7	3.6	3.6	3.6	3.4	5.5	5.5	4.2
Grid UoS	£/kW/yr	4.3	4.3	4.3	4.3	4.3	4.3	4.5	4.5	4.5
CO2 transport and storage costs	£ / tonne CO2	12	12	12	12	12	12	12	12	12

Source: Pöyry analysis of PB (2012)

Table 23 – Central cost assumptions for gas CCS

		Gas pre-combustion			Gas post-combustion		
		ZOAK	FOAK	NOAK	ZOAK	FOAK	NOAK
Operations							
Predevelopment	yrs	5	5	4	5	5	4
Construction	yrs	4.5	4.5	4	4.5	4.5	4
Plant life	yrs	25	25	30	25	25	30
Availability	%	93%	93%	93%	93%	93%	93%
Efficiency (HHV)	%	38%	38%	38%	46%	46%	46%
CO2 scrubbing	%	82%	82%	82%	88%	88%	91%
Capex							
Predevelopment costs	£,000/MW	44	30	28	45	30	25
Regulatory costs	£,000/MW	1	0	0	1	1	1
Construction cost	£,000/MW	2419	1612	1369	2123	1415	1202
Infrastructure cost	£,000	21750	14500	14500	21750	14500	14500
Opex							
Fixed O&M	£/kW/yr	30	30	25	24	24	20
Vble O&M	£/MWh	1.5	1.5	1.2	1.9	1.9	1.6
Insurance	£/kW/yr	6.4	6.4	5.5	5.7	5.7	4.8
Grid UoS	£/kW/yr	3.1	3.1	3.1	3.1	3.1	3.1
CO2 transport and storage costs	£ / tonne CO2	12	12	12	12	12	12

Source: Pöyry analysis of PB (2012)

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ANNEX B – SENSITIVITY RANGE ASSUMPTIONS

In this Annex we list the different sensitivity cases we have performed (in addition to our 'base case') to investigate the impact of uncertainty in input cost assumptions on the strike prices we have derived.

Our general approach is to identify the drivers of levelised costs for each technology (for example capital cost or discount rate), and to adjust these to 'high' or 'low' values which we consider are plausible reflections of the range of uncertainty in these inputs. We then re-run our strike model to derive the impact on strike prices.

Offshore wind

For the lower deployment scenario:

1. Higher capex – add 20% to central assumption.
2. Lower capex – subtract 20% from central assumption.
3. Higher load factor – add 2 percentage points to each project.
4. Lower load factor – subtract 2 percentage points from each project.
5. Higher discount rate – add 2% before 2020 then add 1.5%.
6. Lower discount rate – Subtract 2% before 2020 then 1.5%.
7. Discount rate stays constant at 12.4% (i.e. no future reduction).
8. 15 year economic life (i.e. investment decision takes no account of period beyond CfD).
9. PPA 'route to market' discount – increase from 10% to 20%.

For the higher deployment scenario:

10. Set capital cost, operating cost, and discount rate to most favourable end of the range to represent a 'low cost' world which would be consistent with high deployment. Reduce capital cost and operating cost by 20%, and discount rates as in 6 above. Increase load factor by two percentage points.

Onshore wind

1. Higher capex – add 20% to central assumption.
2. Lower capex – subtract 20% from central assumption.
3. Higher load factor – add two percentage age points to each project.
4. Lower load factor –subtract two percentage points.
5. Higher discount rate – add 1.5% before 2020 then add 1%.
6. Lower discount rate – subtract 1.5% before 2020 then 1%.
7. 15 year economic life (i.e. investment decision takes no account of period beyond CfD).

Nuclear

1. Higher capex – move to high end of LCOE model range (based on range in PB(2012) study).

2. Lower capex – move to lower end of LCOE model range (based on range in PB(2012) study).
3. Higher discount rate – add 2% before 2020 then add 1.5%.
4. Lower discount rate – subtract 2% before 2020 then 1.5%.
5. 40year CfD term and project life (i.e. ignore any revenue beyond 40 years).

CCS

1. Higher capex – move to high end of LCOE model range.
2. Lower capex – move to lower end of LCOE model range.
3. Higher discount rate – add 2%.
4. Lower discount rate – subtract 2%.
5. High fuel prices – use high case for Updated Energy and Emissions Projections 2012.
6. Low fuel prices – use low case for Updated Energy and Emissions Projections.
7. High T&S charges – high end of LCOE model range.
8. Low T&S charges – low end of LCOE model range.
9. 15year CfD term and project life (i.e. ignore any revenue beyond 15 years).

Biomass conversion

1. Higher capex – add 25% (based on MML (2011a)).
2. Lower capex – subtract 25% (based on MML (2011a)).
3. Higher discount rate 11% (i.e. add 1%).
4. Lower discount rate 9% (i.e. subtract 1%).
5. Higher fuel cost – high end of range quoted in MML (2011a).
6. Lower fuel cost – low end of range quoted in MML (2011a).

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ANNEX D – LIST OF ACRONYMS

ABWR	Advanced Boiling Water Reactor
ASC	Advanced supercritical
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CfD	Contract for Differences
CfD FiTs	Contract for Differences Feed-in Tariff
CRTF	Cost reduction task force
DECC	Department of Energy and Climate Change
EMR	Electricity Market reform
EOR	Enhanced oil recovery
EPR	European Pressurised-water Reactor
FID	Final Investment Decision
FiT	Feed-in Tariff
FOAK	First of a kind
GDA	Generic Design Assessment
GHG	Greenhouse gas
IED	Industrial Emissions Directive
IGCC	Integrated gasification and combined cycle
LCF	Levy Control Framework
LCOE	Levelised cost of electricity
LCPD	Large Combustion Plants Directive
NER	New Entrant Reserve
NOAK	Nth of a kind
NREAP	National Renewable Energy Action Plan
O&M	Operations and maintenance
OFTO	Offshore Transmission Network Operator
PPA	Power purchase agreement
PWR	Pressurised water reactor
RO	Renewables Obligation

ROCs	Renewables Obligation Certificates
T&S	(CO_2) transport and storage
TNUoS	Transmission Network Use of System
ZOAK	Zero-th of a kind

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